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PETROLEUM SYSTEMS RELIABILITY ANALYSIS. A PROGRAM FOR PREVENTION OF OIL SPILLS USING AN ENGINEERING APPROACH TO A STUDY OF OFFSHORE AND ONSHORE CRUDE OIL PETROLEUM SYSTEMS. VOLUME II. APPENDICES

J. E. Ritchie, Jr., et al

Computer Sciences Corporation
Falls Church, Virginia

August 1973

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The analysis examined in detail the causes of polluting spills from selected petroleum systems (onshore and offshore crude oil drilling, production, and gathering/distribution systems). The study included the compilation of data from Federal, State and industrial spill reports, a field survey of the various types of facilities, and an analysis of spill-causing failures. EPA prevention regulations presently under consideration envision the preparation of prevention plans (called Spill Prevention, Control and Countermeasure Plans, or SPCC Plans) by facilities to prevent discharges of oil. This analysis should be invaluable in preparing and evaluating these plans. The results will indicate operating procedures and equipment which are spill prone, and failures which can be anticipated and, in many cases, prevented. The application of preventive maintenance, operating procedures and, equipment which have been used effectively by the industry to successfully combat failures are discussed. Volume II contains eleven appendices that provide the detailed information upon which the findings are based. (See also W74-02947)(EPA)

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August 1973

PETROLEUM SYSTEMS RELIABILITY ANALYSIS

A Program for Prevention of Oil Spills Using an Engineering Approach to a Study of Offshore and Onshore Crude Oil Petroleum Systems

VOLUME II - APPENDICES

Prepared by

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Washington, D. C. 20460

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This report has been reviewed by the Office of Water Programs Operations, EPA, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Environmental Protection Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

FOREWORD

The 1970 and 1972 amendments to the Federal Water Pollution Control Act required that the President issue regulations establishing procedures, methods and equipment and other requirements for equipment to prevent discharges of oil into the navigable waters of the United States. The responsibility of issuing these regulations for nontransportation-related facilities was delegated to the Environmental Protection Agency.

An examination of reported oil spills was begun by EPA in order to draft workable and effective regulations. There was a great deal of data on oil spills, especially from production and transportation facilities, which indicated a similarity of spills from certain classes of facilities. However, these data were widely scattered among a number of different governmental sources, and the individual agency sources had varying elements of information within their spill reports, depending upon management needs and emphasis.

It was apparent that a careful collection and examination of available spill data, and a technical analysis of spill patterns and equipment failure was needed. This need generated a contract which in turn produced this study entitled, "Petroleum Systems Reliability Analysis."

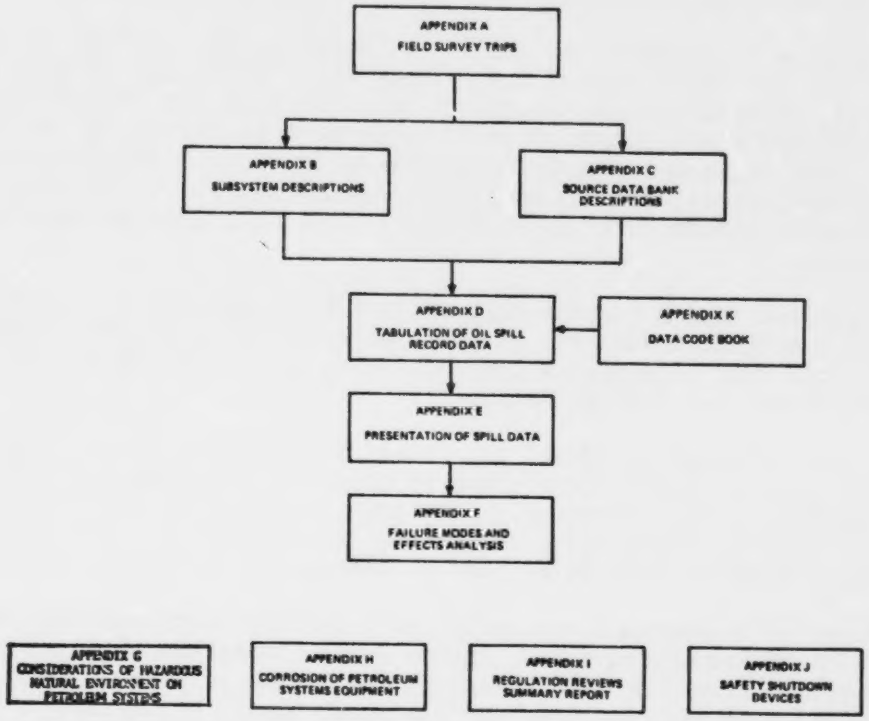
The analysis examined in detail the causes of polluting spills from selected petroleum systems (onshore and offshore crude oil drilling, production, and gathering/distribution systems). The study included the compilation of data from Federal, State and industrial spill reports, a field survey of the various types of facilities, and an analysis of spill-causing failures.

EPA prevention regulations presently under consideration envision the preparation of prevention plans (called Spill Prevention, Control and Countermeasure Plans, or SPCC Plans) by facilities to prevent discharges of oil. The analysis contained in this study should be invaluable in preparing and evaluating these plans. The results will indicate operating procedures and equipment which are spill prone, and failures which can be anticipated and, in many cases, prevented. In addition, the application of preventive maintenance, operating procedures and, in some cases, equipment which have been used effectively by the industry to successfully combat failures are discussed.

This study has been prepared in two volumes; Volume I contains the Engineering Report, and Volume II contains Appendices.

The Engineering Report presents, in four sections, the findings resulting from the study. The conclusions and recommendations are presented in Sections 1 and 2, respectively. Section 3 describes a systems approach to spill prevention, and documents application of the approach to Drilling, Production, and Gathering/distribution Systems. Section 4 presents a spill prevention program for crude oil systems, based on a review of petroleum facility SPCC plans and using techniques developed during the study. The Engineering Report also includes a bibliography and glossary.

Volume II contains eleven appendices that provide the detailed information upon which the report is based. Relationships between appendices are shown by the following diagram.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SAFETY SHUTDOWN DEVICES

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ABSTRACT

EPA's oil spill prevention program has been advanced with methodology for evaluating Drilling, Production, and Gathering/Distribution Systems plans to prevent spillage of crude oil. The program responds to the Federal Water Pollution Control Act, as amended in 1972. The methodology has been designed for use by EPA Regional personnel, and to minimize requirements for the special skills of a petroleum engineer or systems analyst. The scope of the study included offshore and onshore facilities in the Gulf of Mexico, Louisiana, Texas, California, and Alaska. Field surveys providing firsthand observation of selected facilities are documented in the report. Approximately 15,000 spill records were collected from 20 data sources covering major oil-producing States. Half of these records were identified as being useful to the study and are included in the report.

The report presents, for use by EPA Regional O&HM personnel, a set of checklists which identify system points of spill vulnerability, and spill prevention guidelines applicable to these points. Application of these guidelines to a specific facility will require judgment and allow innovative spill prevention measures.

This report was submitted by Computer Sciences Corporation in fulfillment of Project Number 1508HOC, Contract 68-01-0121, under the sponsorship of the EPA Office of Water Programs Operations.

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APPENDIX A

FIELD SURVEY TRIPS

A.1 INTRODUCTORY SUMMARY

The spill prevention program described in this report relies heavily on the operations and findings of field survey trips. Through the cooperation of a number of oil companies and governmental agencies, the field survey provided the study team with current, first hand exposure to existing petroleum systems, operation and maintenance practices, local conditions and environments, and also provided the opportunity for discussion with petroleum industry personnel. This appendix is included to provide an understanding of the benefits resulting from the study team's observations. The basic purpose of the field surveys was to develop an information baseline through observations, discussion, and study of the more significant continental United States' oil producing areas. Survey emphasis was guided by the following criteria:

1. Visit a sufficiently large number of selected facilities to provide a representative sample of present petroleum systems and system state-of-the-art.
2. Observe systems over a wide range of ages and configurations.
3. Observe both onshore and offshore operations.
4. Observe operations in various geophysical areas and climatic conditions.

The information gained from these surveys, supplemented through study of the technical literature, was instrumental in the development of the system description of Volume I, the failure modes and effects analysis documented in Appendix F, and in the interpretation spill data tabulated in Appendix D.

The remainder of this appendix presents an overview of field survey activity; a summary of significant findings; and summarized reports of survey trips and visitations.

A.2 OVERVIEW OF FIELD SURVEY APPROACH AND ACTIVITY

The field survey trips and visits generating reportable facility information are identified in the following paragraphs with general comments concerning the prevailing factors of area choice. State and Federal agencies in these areas and two Government agencies in Canada were contacted for background information and pertinent data. Several manufacturers of oil field equipment and controls were also visited. All visits were accomplished during the period June 1971 through August 1972.

A.2.1 Three Inland Oil Fields and a Pipeline Pumping Station in Texas

Texas produces approximately one-third of all domestic crude oil. Houston, in the coastal area, is the hub of the petroleum industry. The city afforded an opportunity to visit equipment manufacturers, service companies, and nearby crude oil production and pipeline facilities. A cross-section of operations and technology exists which ranges from very old to modern. The producing wells range from high capacity to nearly depleted stripper operations. The field locations chosen for visitation were on dry land, but near coastal waters and in the watershed of a high rainfall belt.

A.2.2 Three Offshore Fields and Related Shore Crude Oil Handling Facilities and a Land Oil Field in Alaska

Alaska was selected to provide information on the effects of a cold environment on both land and offshore operations. There is currently no significant activity on the North Slope where arctic climate exists; therefore, that area was not visited. Cook Inlet, however, provides a unique cold weather, offshore environment. A land operation in southern Alaska was also selected.

A.2.3 Three Offshore Operations and Related Shore Facilities and Three Other Shore Installations in California

California produces approximately one-ninth of all domestic crude oil and virtually all oil production of the nation's west coast. Both onshore and offshore production exist. Offshore operations are in both protected and exposed coastal waters, while some onshore facilities are in densely populated urban areas. Facilities range in age from very old to modern.

A.2.4 Six Offshore Fields and Related Shore Crude Oil Handling Facilities and Two Tidal Zone Fields in Louisiana (State and OCS Leases were Included)

Louisiana produces approximately one-fourth of all domestic crude oil, the majority of which comes from the coastal area. This region is characterized by high-productivity wells in the offshore and adjacent tidal areas. Offshore oil production comes from platforms situated in water depths to well over 200 feet. Nearshore operations are in tidal marshes, lakes, bays, and sounds.

A.3 AN OVERVIEW OF SIGNIFICANT OBSERVATIONS

Some of the more significant observations and findings derived from the field surveys are highlighted below:

1. Although the petroleum systems studied generally comprise a definable set of processes "typical" configurations could not be identified. As a result of wide differences in naturally occurring conditions, standardization among systems, subsystems, or equipment was not exhibited at any level. This complicated the development of the failure modes and effects analysis presented in Appendix F.

2. Evidence among several companies indicates that formal spill contingency plans have been developed and oil companies have ascribed to these on a cooperative basis. These plans list well-defined emergency procedures, pertinent notifications, names, emergency telephone numbers, and other information, and receive mutual, cooperative implementation regardless of spill source.

3. The application of automated oil field production methods is increasing. As a result, it has been necessary to develop highly refined procedures for routine and preventive maintenance. The value of these programs has been recognized and adapted to some nonautomated production systems. However, in many cases, documentation is relatively informal or lacking in some detail with respect to operation, inspection, and preventive maintenance.

4. Competition among oil field hardware manufacturers has made available to the industry several lines of rugged and dependable components, as well as less dependable components at a lower price. The more expensive components exhibit reliability and failsafe considerations in their design.

5. A major company conducted a failure modes and effects analysis (FMEA) on a principal offshore platform facility and a reliability study on a major land-based computerized field, and is performing an FMEA on a portion of a producing facility which will be submerged in the deep seas.

6. The U.S. Geological Survey (USGS) has collected large quantities of refined information on equipment and procedures required on the outer continental shelf (OCS) which could be used in reliability analysis; had a study made by NASA personnel to determine the feasibility of applying reliability analysis methods to oil field systems in the OCS area; and is conducting three other related studies, one of which will include FMEAs of six offshore platforms of various complexities.

7. Sand production is a major problem in petroleum systems. It causes blockage (sanding up) of tubing and equipment and erosion (sand cutting) of tubing, pipe, valves, fittings, and vessels. The use of sand control techniques in well completion and workover procedures limits sand production but does not eliminate it. Some advanced preventive maintenance procedures such as ultrasonic inspection to determine wear and tear rates in critical areas, have been developed to detect the problem.

8. Various schemes are used to remove accumulated sand from vessels by washing with an oil stream. One such scheme uses a timer to provide intermittent washing cycles. Desanding equipment is used to remove sand from oil and water "in-stream." Various means are used to reduce velocities of sand-laden fluids to control erosion. An example would be a choke downstream of a dump valve or elbow.

9. One company has studied internal pipe wear as a function of fluid velocity and determined that velocities of 75 feet per second or greater cause severe acceleration of pipe wall loss. As a result, flow demands on all flowlines are reviewed every 6 months and, where necessary, flowlines are replaced and flow rates are adjusted to less than 75 feet per second. Produced sand is laundered before its disposal in overwater operations.

10. External corrosion of pipelines, offshore platforms, and other metallic equipment can be controlled largely by cathodic protection and protective coatings. There is a special problem in the splash or wave wash zone in overwater operations, which in some cases is corrective by application of a vulcanized rubber coating, which has been found to be especially effective.

11. Internal corrosion is not controllable cathodically. Effective means include the use of corrosion inhibitors by continuous injection of small quantities into the fluid being pumped, and by "slug" treatment using water plugs. Occasionally, corrosion attributable to anerobic bacteria was identified. This apparently can occur where the culture is introduced into the pipeline system via drain sump fluids that are pumped ashore with the produced oil and saltwater. In these cases, biocides can be introduced into the drain sumps to control the problem. In some instances, protective coatings can be applied to the interior of pipe, fittings, tanks, and other vessels.

12. Sump systems have become required equipment in overwater operations and are routinely found in many land operations. These sumps centralize the collection of all drips and accidential spills, and are also used for blocks and drain procedures in repair operations. Spills have resulted from sump overflows due to failure of automatic, fluid-level controlled disposal pumping methods. Overflow can result from failure of the

disposal pump by overload due to hard rain. Some of these problems can be overcome by use of redundant pumps and controls, automatic timer switches with liquid-level override, and the addition of a water leg to siphon excess water.

13. Personnel training has come into strong focus in recent years. Increased complexity and refinement of equipment and procedures have required extensive operational training in the petroleum systems studied. Oil spill prevention and cleanup have become subjects for intensive training for all personnel levels in the crude oil Production and Gathering/Distribution systems. Blowout prevention has become more of a science than an art. It is now recognized that this technology must be learned both in the classroom and by experience on the drilling rig floor. Accordingly, there has been a proliferation of training programs offered to personnel, ranging from short lectures using electronic simulation to formal courses that include "hands-on" well-killing procedures on a full-scale blowout training well, such as one recently installed at Louisiana State University and financed by industry. Hardware and procedures have been developed to the point that blowouts can be virtually eliminated if rig floor personnel have the proper training. Some elements of industry have begun to spend considerable funds for training in this area. Until recently, there was reluctance to provide such training because of the transient nature of rig floor employees.

14. There are at least eight manufacturers actively engaged in the development of a second generation subsurface safety valve for flowing wells, commonly known as a storm choke. The new configuration will stress surface control. A number of these devices have been in use in other

areas of the world. Improvements are being sought in those currently available designs, and entirely new concepts are also being developed. Several prototypes of these new designs are undergoing testing by several major producers using actual well conditions. The USGS is revising regulations dealing with subsurface safety valves to encourage a phased changeover to the use of surface-controlled configurations in the OCS area.

A.4 TRIP AND VISIT REPORT SUMMARIES

This paragraph provides summaries of the trips and visits made during the field survey. In preparing these summary reports, some visits, and some discussion and observations during other visits, have been omitted when, in our judgement, these actions seemed appropriate. The remainder of this appendix presents the summary reports, organized by trip.

A.4.1 Trip Number 1 - Houston, Texas Area Survey (4 through 13 August 1971)

Visit Number 1 - A Major Company Producing Tanks, Pressure Vessels, Etc.

Purpose - To observe maintenance and repair activities in support of the company's products provided to the oil industry.

Personnel Contacted - Vice President of Sales, District Manager, and Sales Engineer.

Observations - The equipment provided to the oil industry by this manufacturer indicate that a skilled man with proper parts can repair the valving associated with the vessels with ordinary tools in relatively short times. For example, it was demonstrated that valve seat replacement could be performed in 10 minutes.

Visit Number 2 - Company A's Production Operations in a Large Field Near Houston

Purpose - To observe production operations and procedures.

Personnel Contacted - Regional Superintendent, Area Engineer, and Computer Specialist.

Observations - The operation is located on a large field discovered in the 1930s with gas-lift aided sweet crude flowing wells. The field and well head areas showed little evidence of oil spillage. Personnel observed the gathering, separation/treatment, metering, and gathering to local storage for pipeline sale. Company A has a computer system for monitoring flow parameters and plans to extend this system, including remote control, to other fields. The company provides, to a large extent, its own maintenance and does not rely on manufacturers' service organizations. Figure A-1 depicts the general production operation on a typical lease and the field ACT station.

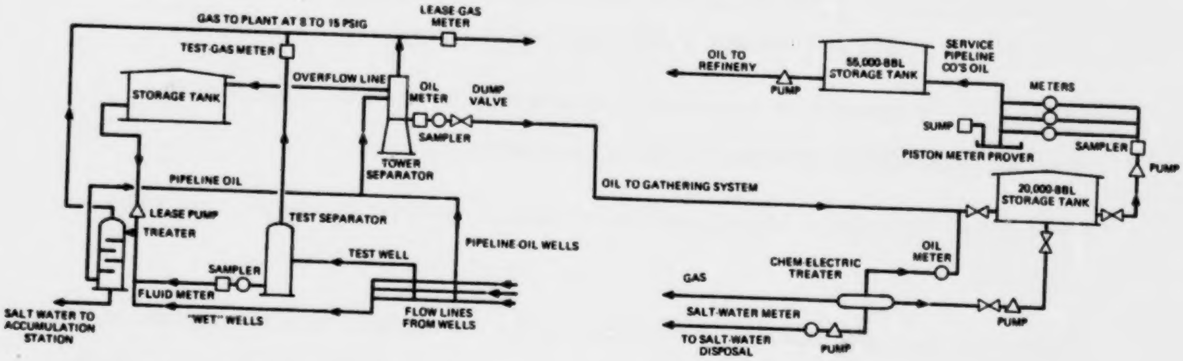

GAS TO PLANT AT 8 TO 15 PSIG
LEASE GAS METER
TEST GAS METER
STORAGE TANK
OVERFLOW LINE
OIL METER
DUMP VALVE
SAMPLER
TOWER SEPARATOR
PIPELINE OIL
LEASE PUMP
TREATER
TEST SEPARATOR
TEST WELL
PIPELINE OIL WELLS
SAMPLER
FLUID METER
"WET" WELLS
FLOW LINES FROM WELLS
SALT WATER TO ACCUMULATION STATION
OIL TO REFINERY
PUMP
55,000-BBL STORAGE TANK
SERVICE PIPELINE CO'S OIL
METERS
SUMP
PISTON METER PROVER
SAMPLER
PUMP
OIL TO GATHERING SYSTEM
20,000-BBL STORAGE TANK
OIL METER
CHEM-ELECTRIC TREATER
GAS
SALT-WATER METER
TO SALT-WATER DISPOSAL
PUMP
PUMP

Figure A-1. Company A's Typical Operations, Simplified Flow Diagram

Visit Number 3 - Company B's Production Operations in a Large Field Near Houston

Purpose - To observe production operations and procedures.

Personnel Contacted - Environmental Coordinator, District Superintendent, and Acting Field Superintendent.

Observations - Company B has a large field of gas-lift aided sweet crude flowing wells. The entire area was well kept with several environmental protection features.

Wells near highways were equipped with storm chokes. A demonstration of the salt water treatment closed system was given by allowing a heavy flow of crude oil from one salt water inlet line to this system. After passing through a multistage skimming pond, the outlet salt water showed no evidence of sheen. Company B also has a computer system for monitoring, but not controlling, oil flow parameters.

Visit Number 4 - Company B's Production Operations in an Old Field Near Houston

Purpose - To provide a contrasting view of early oil field practices compared with those observed in Visits 2 and 3.

Personnel Contacted - Same as during Visit 3.

Observations - A short visit was made to an early 1900s oil field. This nearly depleted field, primarily pumping-aided production wells, appeared to have experienced considerable prior oil spillage.

Visit Number 5 - Texas Railroad Commission, Austin

Purpose - To determine the types and quantities of spill data available at the Commission that would be applicable to the present study.

Personnel Contacted - Messrs. Rex King and Guy Mathews.

Observations - The Commission maintains a large file of oil spills reported in Texas and made this file available. With over 4000 spill reports in 12 districts since January 1970, the team concentrated on Districts 1 and 3 to develop data for subsequent and more detailed analysis. Two reported major causes for spillage were pipeline corrosion and separation/treatment equipment valve malfunction.

Visit Number 6 - Company B's Pipeline Station Near Houston

Purpose - To observe pumping station and pipeline operations and procedures.

Personnel Contacted - Assistant Operations Manager, Station Manager, and two Station Engineers.

Observations - The station's pumping and manifolding facilities appeared to be extremely well kept. According to station personnel, spillages occurred more frequently in the pipelines than in station facilities despite that station facilities are more complex and involve mechanical operation. This was attributed to the greater opportunity for personnel observation and preventive maintenance.

Visit Number 7 - A Drilling Control and Monitoring Device Manufacturer

Purpose - To examine and discuss various drilling control devices.

Personnel Contacted - Vice President and two engineers.

Observations - Examined and discussed the operation of a number of drilling control devices. These included downhole blowout preventers, drilling mud weight, and flow rate measurement devices and recording equipment. Of particular interest was an opportunity to see an experimental computer-operated drilling well control system.

Visit Number 8 - A Major Company Producing Well Accessory Equipment

Purpose - To increase familiarization with available well accessory equipment.

Personnel Contacted - Manager of the Houston Office.

Observations - Examined and discussed operation of automatic surface control valves and several types of subsurface storm chokes. Many of those devices are designed in accordance with fail-safe principles. Certain types are made of a steel particularly resistant to corrosion from the sulphur compounds present in sour crude.

Visit Number 9 - A Drilling Equipment Rental Company

Purpose - To increase familiarization with various drilling tools and blowout preventers.

Personnel Contacted - Company owner.

Observations - Inspected a variety of drilling tools including ram-type surface blowout preventers. The massiveness and ruggedness of equipment was impressive.

Visit Number 10 - Revisit to Company Visited in Visit 1

Purpose - To discuss questions raised by review of Texas Railroad Commission data.

Personnel Contacted - Sales Engineer.

Observations - As a result of reviewing the data maintained by the Texas Railroad Commission, the team returned to obtain further information on oil separator/treater equipment, valves, and controls.

Visit Number 11 - A Drilling Tool Rental Company

Purpose - To increase familiarization with additional drilling equipment other than that observed during Visit 9.

Personnel Contacted - Company owner.

Observations - Obtained a broader view of drilling tools available to the petroleum industry.

A.4.2 Trip Number 2 - Alaska Survey (30 August through 14 September 1971)

Visit Number 1 - U.S. Coast Guard, Juneau, Alaska

Purpose - To introduce the program to the Coast Guard and to extract any and all crude oil spill data for analysis and evaluation.

Personnel Contacted - Lt. Westling.

Observations - As a result of an earlier phone call from CSC and a program Lt. Westling had just completed, a data summary of Cook Inlet spills dating from 14 June 1968 through 26 July 1971 was ready upon the team's arrival. In addition to these data Lt. Westling agreed to forward additional data as reports are received. One additional reference suggested by Lt. Westling is a document generated by the University of Alaska entitled "Quantitative Assessment of Oil Pollution Problems in Cook Inlet," Report No. R-69-16, dated January 1970.

Visit Number 2 - Oil and Gas Conservation Board, Calgary, Alberta, Canada

Purpose - To obtain crude oil spill data for analysis and evaluation from environments similar to that in Alaska.

Personnel Contacted - Assistant Manager, Drilling and Production; and Engineer, Drilling and Production Office.

Observations - A summary of crude oil spills in the Alberta area for 1970 and 1971 was provided. Copies of Oil and Gas Acts, Regulations, maps of Alberta oil fields and pipelines, and copies of monthly and weekly statistics were obtained. Mr. Edgecombe indicated that his field offices may have more detailed information on the crude oil spills he had summarized. He also said that pipeline spills did not fall under his jurisdiction; pipelines were under the jurisdiction of the Alberta Division of Mines and Minerals.

Visit Number 3 - Edmonton Field Office of Drilling and Production and the Division of Mines and Minerals, Edmonton, Alberta, Canada

Purpose - To obtain detailed information on crude oil spillage from the Edmonton Field Office of Drilling and Production and to obtain pipeline spill data from the Division of Mines and Minerals.

Personnel Contacted - Duncan LaBallister, Edmonton Field Office for Drilling and Production, and Mr. A. L. (Larry) Berry, Superintendent of Pipelines, Division of Mines and Minerals.

Observations - Mr. LaBallister said that he did not have additional detail to the summaries that Mr. Edgecombe had previously provided us. Mr. Berry indicated that his records on pipeline oil spillage were of some detail. However, he was not at liberty to provide the records unless required by court order. He did provide general statistics on the category of oil spillage cause and the percent of the total events caused by each category. Mr. Berry appeared to be knowledgeable on the weaknesses of standards relating to pipelines, which the oil industry uses in both the United States and Canada. He indicated several of the weaknesses which he felt should be corrected. A copy of Alberta's Pipeline Act was obtained.

Visit Number 4 - Environmental Protection Agency, Anchorage, Alaska

Purpose - To obtain spill data for analysis and evaluation.

Personnel Contacted - Ray Morris of the EPA office

Observations - Mr. Morris indicated that his file on oil spillage was the most complete in the Alaskan Area, including State and Coast Guard files. The records of the events relating to spillage of crude oil were examined.

Visit Number 5 - Alaska Department of Natural Resources, Division of Oil and Gas

Purpose - To obtain oil spill data for analysis and evaluation.

Personnel Contacted - Homer L. Burrell, Director of the Division of Oil and Gas, and John Miller and Lonnie Smith, Engineers.

Observations - Mr. Burrell said that any crude oil spillage event would be in EPA's files. He said he may be able to provide more detail to specific spills and blowouts, so we left a summary of EPA-recorded spills with him. He said he would mail the additional information to CSC along with State regulations and pool rules for wells. Warren McFall of EPA's Anchorage office said that Mr. Burrell's division also makes periodic checks and exercises of safety valves on wells. Mr. Burrell was recontacted to obtain records of failures detected during these checks.

Visit Number 6 - Company C's Onshore Oil Field

Purpose - To observe Company C's production operations and procedures as well as those of an independent drilling contractor.

Personnel Contacted - Company C's Alaskan Division Production Superintendent, Field Production Foreman, Gas Plan Foreman, and a Tool Pusher for the Drilling Contractor.

Observations - The Field Production Foreman had a collection of failed items and discussed the problems that Company C has experienced in this field. The principal problems have been cutting from sand and plugging of equipment with asphaltene.

The wells at this facility are on artificial gas lift. As a result of this, storm chokes are installed in some wells (and in time will be installed in all wells), a high/low valve is at each well head to shut in the well if a break occurs in the flow line, flow lines are extended out from well head with long radius bends in the lines to alleviate cutting by sand, and a motor gate valve is located at the gathering point. The gathering points and separators are located in Butler building enclosures which have monitored "sniffer" leak detection systems which are forwarded via two-way radio to patrol cars. An 8-inch gathering line from the LACT to a pipeline company storage tank is scraped every 3 or 4 days in summer and daily in winter. The field has approximately 58 wells of which 36 are in production on 6000-psi gas lift. About six to ten wells are on workover activity each summer. The sand problem has migrated to pump station, causing seal problems there.

Visit Number 7 - Visit to Company A's Cook Inlet Field Operations

Purpose - To observe offshore production facilities and procedures in two different fields and onshore treatment and storage facility.

Personnel Contacted - Production Superintendent and Production Foreman

Observations - Minimum oil is stored on the platforms. Instead, pipelines to the shore storage facility are used to eliminate potential hazards. One platform's production is interfaced to the shore storage via two 10-inch pipelines and the other platform via two 8-inch pipelines. In both instances, one pipeline carries gas, the other crude oil. However, should a problem occur in the oil pipeline, crude oil production can be transported through the gas pipeline. The first platform consists of two flowing wells and eight wells on hydraulic lift, as well as several inactive wells which are to eventually be used for water flooding. The latter platform consists of hydraulic lift wells only. The configurations of the two platforms are essentially the same. The crude oil flows from the well head to two 250-psi separators (one three-phase, the other two-phase) and through a 40-psi separator used as a free water knockout. Equalization occurs between the two high pressure separators, alleviating spillage due to failure of the isolation valve between the high pressure separator and FWKO. The surface-controlled subsurface safety valves are about 250 to 300 feet below the mud line in the well tubing string, and include a high/low pressure valve at the well head, and high and low level valves on each separator which are alarm-detectable at levels which allow adequate warning before overflow or draining will occur. In the event of a failure, the safety valves will react in sequence back to the well, resulting in shut-in. Monitoring and fault isolation panels are located in the Production Maintenance quarters The platform equipment also includes a skim tank and two test separators. The FWKO and skim tank were used earlier to condition the salt water prior to disposal into the Inlet. Subsequent regulations prohibited salt water disposal into the Inlet. Consequently, the conditioned salt water is now injected with crude oil into the pipeline for separation and treatment at the onshore storage facility. Due to paraffin formation, scrapers are periodically run through the platform to shore pipelines. During the winter, scraper trips are performed daily; during the summer, about once every 3 or 4 days. The onshore storage and treatment facilities consist of a heat exchanger, four heater treaters, two serial free water knockout tanks, two 10,000-barrel good oil storage tanks with equalization, and a bad oil storage tank which will accept overflow from either or both of the good oil tanks. The bad oil tank is fed back to heater treaters for further treatment. Monitoring and remote valve controlling is centralized in a control building. Each heater treater has an interface level control and an oil flare which will ignite any overflowing oil. This flare is separate from the gas flare. The produced salt water is disposed into a salt water evaporation pit.

Visit Number 8 - Visit to Company D's Platform

Purpose - To observe offshore production facilities and procedures.

Personnel Contacted - Production Superintendent and Production Foreman.

Observations - The platform consists of 16 wells, of which six are used for water injection. The highest producing well averages approximately 1100 barrels per day. The wells use gas lift. Several of the wells are of a dual completion type.

the rest single completion. The separation area consists of a production separator, a test separator, as well as a skim tank and small slop oil tank. The pressure disc outlet configuration on the separator allows for overflow to enter the skim tank in the event of a highlevel valve failure. Downhole well configurations were obtained. The safety valves consisted of high/low valves for shutting in the well, tubing ball valves, high level separator shutdown alarm valves, high pressure separator valve, and relief valves, intermediate high level crude oil tank alarm, final high level crude oil tank alarm, and a low pressure shutdown system for pipeline. A central monitor and fault isolation room contained indicators to monitor conditions of the various high/low safety valves and the well tubing valve as well as various pressures for the gas lift and the automatic valves. There are two 8-5/8-inch pipelines to shore, one for gas, one for crude oil. The gasline could be switched to transport crude oil if the other experienced a problem. The pipelines are scraped according to the same schedule as Company A. Company D disposed of the produced salt water through shipment of the crude oil to its onshore treatment facility. After separation of the salt water and the crude oil in the heater treaters, the salt water was disposed into a water evaporation pit.

A.4.3 Trip Number 3 - Collection of Texas Spill Data and Attendance of LAGCOE (17 through 22 October 1971)

Visit Number 1 - Texas Railroad Commission

Purpose - To complete the collection of oil spill data from the files of the Texas Railroad Commission.

Personnel Contacted - Rex King; Arthur H. Barbeck, Jr. (Chief Engineer); Roy D. Rayne (Chief of Field Operations); Robert Harris (Assistant Chief Engineer).

Observations - Mr. King was most cooperative in making available the entire file of oil spill reports. The team participated in reviewing the two file drawers of reports, made principally during 1970 and 1971. The team received a summary report of offshore Texas oil and gas production, which indicated that the offshore leases have generally been a disappointment, and lacked the promise that seemed so positive a few years before. Only a few offshore producing wells existed. The personnel interviewed stated with emphasis that no oil spill incidents were known to have occurred offshore Texas.

Visit Number 2 - LAGCOE Attendance

Purpose - To attend the Louisiana Gulf Coast Oil Exposition (LAGCOE) at Lafayette, Louisiana.

Personnel Contacted - Not applicable.

Observations - LAGCOE is held every other year at Lafayette. It is characterized as the "Working Man's Oil Show," displaying the latest related products and services in the oil industry. About 325 exhibitors, restricted to oil industry firms, showed their products at the Blackham Coliseum, nearby buildings, and surrounding grounds. The exhibit area is normally a facility of the University of Southwestern Louisiana and is located on that campus.

The tour of the exhibits proved to be particularly valuable since it provided an opportunity to see equipment, demonstration models, and displays of the services common to the oil industry, and for discussion with knowledgeable personnel manning the booths, many of whom were national and international authorities in the industry. In general, the exhibitors were forthright and informative, answering the many questions the team put to them. The team collected brochures and handout material which provided description of equipments and their operation. The main thrust of the exhibits was to present products meeting oil field requirements (particularly offshore), and to generate interest in sales of their product lines. The team would have had to cover an immense territory and search out many people to gather the information completely and freely displayed at LAGCOE. The visit to LAGCOE also provided information concerning equipment specifications and petroleum system configurations. In addition, much was learned about "failsafe" devices, failure modes of equipment, and a miscellany of oil industry problems and proposed solutions.

A.4.4 Trip Number 4 - Southern California Area Survey (25 October through 5 November 1971)

Visit Number 1 - Company M's Drilling, Production, Storage, and Pipeline Shipping Facilities in the Long Beach, California area.

Purpose - To observe operating equipment and procedures.

Personnel Contacted - Production, Drilling, and Construction and Maintenance Superintendents.

Observations - Discussed facilities and operations briefly prior to being given a conducted tour of several facilities.

The first facility visited was a man-made island consisting of a perimeter of earth-filled armor rock paved with a concrete surface. A retaining wall exists around the island perimeter except at the boat dock wnere a boom is maintained to contain fluid runoff in case of emergency. All island surface areas are constructed to drain toward the center of the island such that all rain, spilled fluids, or liquids used for cleanup are contained on the island. All wells are located in cellars.

Several hardware systems were examined:

- Drilling - Only one rig was in operation. There are several unique features of drilling and completions of the wells:
  - (1) Hole drift can vary up to 70 degrees from vertical
  - (2) Wells are completed on about every 5 acres of the producing horizons
  - (3) The close spacing of the surface locations and subsurface completions require precise drilling techniques
  - (4) Drilling fluids and cuttings are carefully contained in vessels.
- Production - The following production equipment was inspected:
  - (1) Cellars - wellheads, flowlines, valves, and safety equipment
  - (2) Well testers

(3) Free Water Knockout (serving as horizontal separator for gas-water)

(4) Transfer pumps and motors

(5) Safety systems - included visual and audio, fire control, and spill containment. To control spills, each island has a 5-foot retaining wall around it. However, the driveway leading to the boat ramp is much lower (i.e., an elevation increase of about 1 to 2 feet above the island floor).

Onshore facilities include some producing wells, treatment facilities, storage facilities, pipeline facilities, and water treatment facilities. The following onshore equipment was inspected and discussed.

- Flowsplitters - Crude oil from the manmade island flows into a large flowsplitter, then into heater treaters. Crude oil from onshore wells flows into other flowsplitters and thence into other heater treaters.
- Heater Treaters - The treaters operate at about 75 pounds pressure and are used to separate residual gas and water. The gas flows into a tank to dehydration prior to being compressed for transmission to gas treatment (H_2S removal) plant. The water is sent to treatment facilities prior to being reinjected. The crude oil is transferred to storage tanks.
- Storage Tanks - The crude oil is contained in five tanks, two having a capacity of 87,000 barrels each. The other three tanks have a capacity of 28,000 barrels. Three pumps, driven by electric motors, move the crude through a 24-inch line to the ACT unit at the pipeline shipping terminal.
- Pipeline - Although pigs are run every week on the lines moving wet oil from the onshore and offshore wells to the treatment facilities, there is no pig capability in the 24-inch line. Corrosion inhibitors are added to the oil as a protective measure. Company personnel walk the line for above-ground visual inspections of leaks.

- Pipeline Shipping Terminal - The crude oil is manifolded into the purchasers' lines and sent through provers to determine the amount of crude sold. The crude is purchased by several oil companies and transferred to their refineries through several pipelines. High-low pressure sensors are monitored at the pipeline shipping terminal and at the control house near the storage facilities.
- Safety - A control house near the storage facilities has instruments to monitor the treatment and transfer of oil and gas at and between the various facilities. In addition, control panels, colored lights, and audio alarms are provided at treatment and transfer facilities.
- Water Treatment - Figure A-2 shows a schematic diagram of water treatment and injection facilities. This is typical of low volume systems where heater treaters are not used. In other installations, the wash tank is replaced by heater treaters, or the oil output of the wash tank is recycled to heater-treaters for processing. The flotation tank, when overflowed, dumps into a boomed area in the harbor.

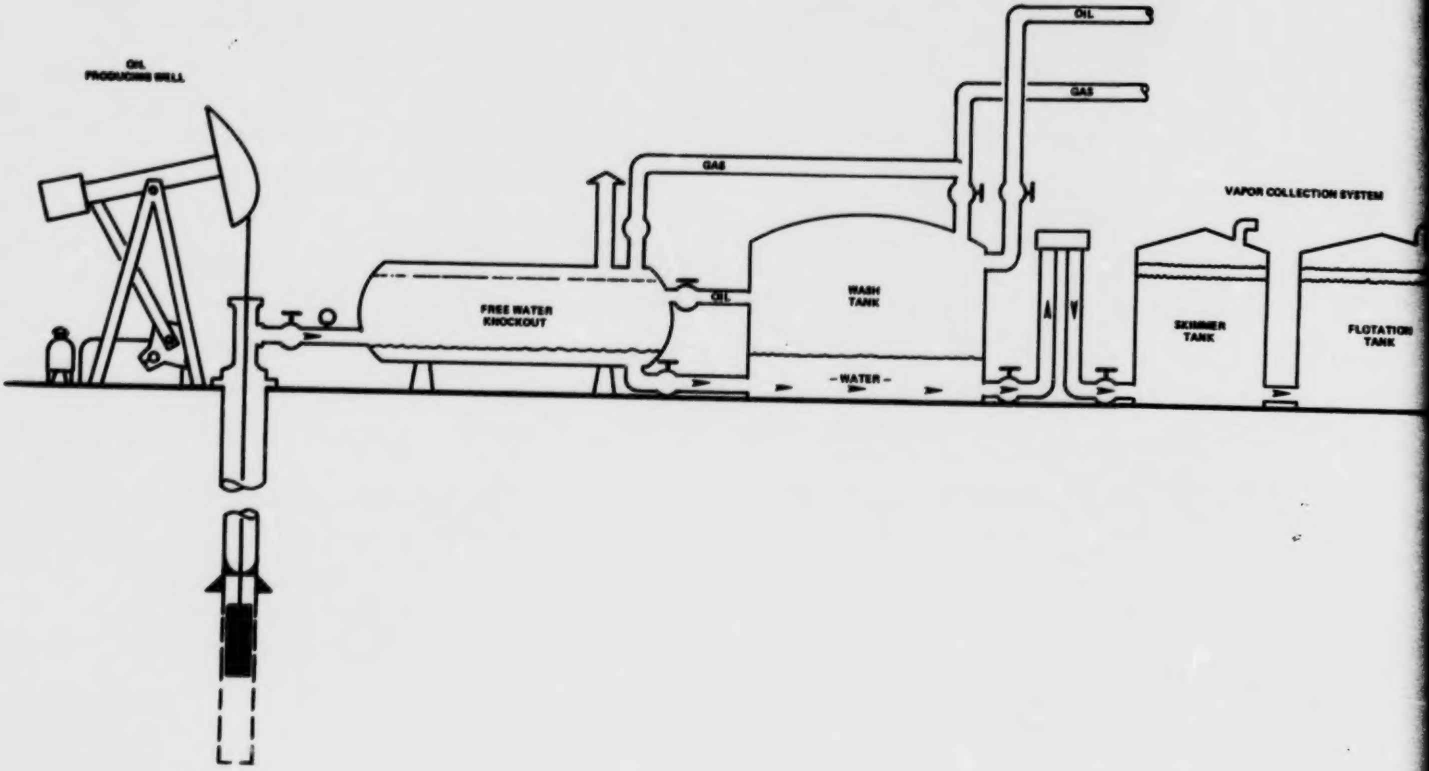
A preventive maintenance program is recorded on sets of three cards (white, green, and yellow). The white cards are used for schedule maintenance; the green describe the equipment, and the yellow record maintenance and completed repair work.

Visit Number 2 - Company B's Crude Oil Production Facilities in Southern California.

Purpose - To observe operating equipment and procedures.

Personnel Contacted - Western Region Production Manager, Environmental Conservation Manager, Area Supervisor, and Area Foreman.

Observations - The production manager described how planned unitization will affect the local producing properties. Production from two units will go into three or four tank batteries instead of the present 50 or more. The number of tank batteries for another unit will be reduced from 34 to one. About 60 to 70 miles of coated, concrete-lined pipe will be laid for the new system. Since the pipe will be laid under streets, the construction will be a time-consuming and expensive.


OIL
PRODUCING WELL
OIL
GAS
GAS
VAPOR COLLECTION SYSTEM
FREE WATER
KNOCKOUT
OIL
WASH
TANK
SKIMMER
TANK
FLOTATION
TANK
– WATER –

A

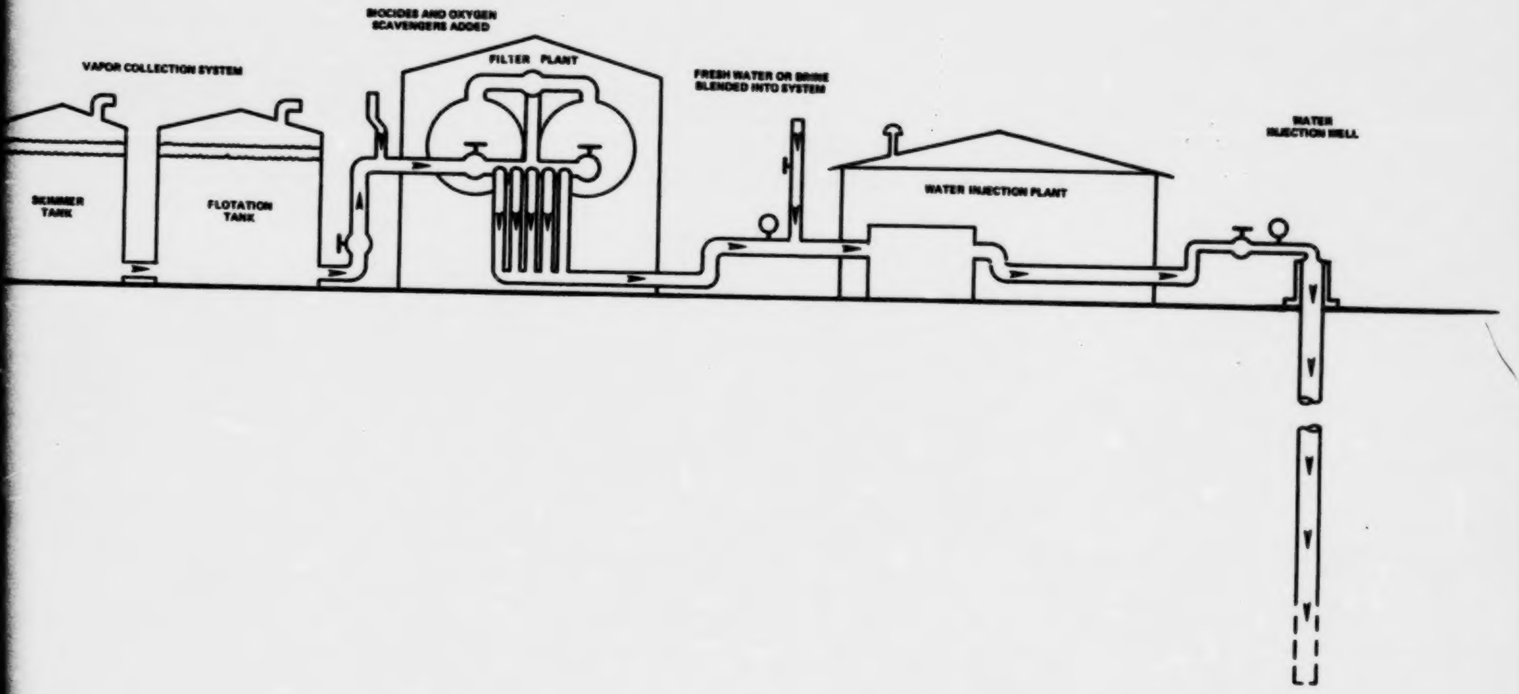

BIOCIDES AND OXYGEN SCAVENGERS ADDED
VAPOR COLLECTION SYSTEM
FILTER PLANT
FRESH WATER OR BRINE BLENDED INTO SYSTEM
WATER INJECTION WELL
SKIMMER TANK
FLOTATION TANK
WATER INJECTION PLANT

Figure A-2. Schematic Diagram of Environmental Control-Waste Utilization (Liquids) Facilities

B

However, Company B feels it will be an economically feasible operation in spite of the rather low daily production rates--2000 barrels of oil per day (12 to 20° API) and 3000 barrels of water (60 percent water cut). Company B, as operator of the unit, feels that the exposure risk to nearby houses (i.e., wells and tank batteries are in back yards) demands unitization. Upon completion of the unitization a preventive maintenance program similar to the one used in another area will be required.

After the meeting a tour was made of the offshore facilities.

- Facility - The facility, located about 1 mile offshore, is a platform of the same general design as those in the Gulf of Mexico. The main platform is on reinforced concrete pilings. A later addition, built to accommodate a storeroom/fire safety equipment and personnel safety area, is on treated steel pilings. The surface area of the main floor is about 1 acre and is designed to permit production from about 75 wells.
- Production - As of this date, 51 wells have been drilled and 37 are actively producing (1500 barrels of oil and 680 barrels of salt water per day). Well spacing on the platform is in rows, with 10 feet between wells. The holes are directionally drilled and maximum deviation from vertical is about 45°. Production is from formations at depths from about 3500 to 7000 feet. Additional wells have not been drilled because of the drilling ban (since lifted) and the need to obtain permits from State agencies. Water is produced from shallow onshore wells and piped to the platform for water flooding. The crude oil varies from about 22 to 28° API.
- Pipeline - Four pipelines (an 8-inch gas line, a 3-inch fresh water line and two 3-inch lines for produced fluids) connect the platform to the onshore treatment plant. The lines are laid on water bottom. When questioned about these lines being caught by dragging anchors, it was stated that boat traffic runs parallel to the lines and anchors inside the marinas. Chemical additives are used for corrosion prevention.

The output of the onshore separation center is:

1. Crude - sold to another oil company
2. Gas - sold to the gas company for local consumption
3. Treated Water - discharged into the river
4. Solid Wastes - trucked to garbage dump.

The equipment design, configuration, and operation in the separation center is standard for this area. One serious potential trouble spot is the discharge of treated water into the river. A serious crude oil overflow from the treaters into the water treatment, into the river, and then into the marina (filled with docked pleasure crafts and large yachts) would have serious repercussions. Company B plans to incorporate the treated water into a closed system, i.e., no discharge.

Figure A-3 is Company B's Test Schedule. The "Xs" indicate which tests are completed each month.

Visit Number 3 - Company N's Crude Oil Production Facilities in the Long Beach, California Area.

Purpose - To observe operating equipment and procedures.

Personnel Contacted - General Manager, Superintendent and Assistant Superintendent of Construction and Maintenance, and Petroleum Engineer

Observations - The production, treatment, storage, and transportation facilities are collected in units and are positioned so that the land area used is minimized.

- Production - Produced well fluids contain about 27,000 barrels of oil and 211,000 barrels of water (i.e., 87 percent determined by cut monitor panel) on a daily basis. There are several producing zones which range in vertical depths from 2,200 to 6,000 feet. The crude varies from 15 to 19 degrees API, measured at the tank farm. The early producing zones were gravel packed, but are now float packed. The casing program is as follows:

This monthly report should be submitted to the District office no later than the 5th day of the following month.

Month: ____________________
Date Submitted: ____________________
Submitted By: ____________________

Test	J	F	M	A	M	J	J	A	S	O	N	D
	Test Schedule											
Master Panel and Flame Detector Panel												
Flow in Fire System Shutdown			X			X			X			X
Gas Detector Shutdown			X			X			X			X
Flame Detector Shutdown			X			X			X			X
Power Failure Shutdown			X			X			X			X
Remote Shutdown			X			X			X			X
High Pressure Shutdown for Shipping Tank			X			X			X			X
High Pressure Shutdown for 8-inch Gas Line			X			X			X			X
Low Pressure Shutdown for 8-inch Gas Line			X			X			X			X
Low Pressure Instrument Air Alarm			X			X			X			X
Shipping Pump Controls and Shipping Tank Bypass System												
High Pressure Shutdown for Shipping Pumps			X			X			X			X
Low Pressure Shutdown, Two Shipping Pumps			X			X			X			X
Low Pressure Shutdown, One Shipping Pump			X			X			X			X
Pump Suction Valves Closure			X			X			X			X
Shipping Tank Bypass System Operation			X			X			X			X
Surface Safety Valves												
Bleed Test to Check Valve Closure	X	X	X	X	X	X	X	X	X	X	X	X
Bleed Test to Check Valve Leaking			X			X			X			X
Subsurface Safety Valves												
Low Pressure Set Point Test						X						X
High Pressure Set Point Test						X						X
Oil Pipelines												
Pressure Test Line 1									X			
Pressure Test Line 2									X			
Weekly Visual Check by Crew Boat	X	X	X	X	X	X	X	X	X	X	X	X
Gas Pipeline												
Pressure Test									X			
Fire Protection												
Start and Run Fire Pumps 15 Minutes Daily	X	X	X	X	X	X	X	X	X	X	X	X
Drain and Flush Main Lines					X					X		
Drain and Flush Foam Lines					X					X		
Flush Cellar Deluge Lines					X					X		
Service Fire Extinguishers												X
Pressure Test Fire Hoses												X
Lubricate Hose Nozzles												X
Test Deluge System Over Compressors										X		
Fire Protection - Separation Center												
Service and Test Foam System									X			
Service Fire Extinguishers									X			
Cathodic Protection												
Read Rectifier Output	X	X	X	X	X	X	X	X	X	X	X	X
Measure Cathodic Protection Potentials			X			X			X			X
Cathodic Protection - Separation Center												
Read Rectifier Output	X	X	X	X	X	X	X	X	X	X	X	X
Measure Cathodic Protection Potentials			X			X			X			X

Figure A-3. Company B Test Schedule

Depth (feet) Ranges	Casing (inches) Diameter
0 to 60 - 80	24
60 - 80 to 800	13-5/8
800 to T.D.	9-5/8

The liner diameter is 6-5/8 inches. Oil is produced by submersible pumps, hydraulic lift, and mechanical lift. The casing hangers are below ground in cellars approximately 5 feet deep. From the wells, the oil is pumped to a house where it is manifolded and sent to treaters (the manifolds have been housed because power oil, in the past, has leaked out and sprayed on private property, causing considerable damage).

- Treaters - From the manifold house, the oil is moved to the free water knockout, which serves as a three-stage flow splitter. A gravity weight float controls water dump; the gas is released at pressures above 20 psi. A water trap alarm has been installed to alert personnel that oil is being dumped into the water system. The oil moves from the free water knockout to the heater treaters. The steel lines from the heater dump valves are being replaced with glass and glass flanges. Bronze valves are used in the treaters for valves smaller than 2 inches and stainless steel for those larger than 2-inches. Glass is used throughout the treaters where temperature and pressure permit. The gas shipped from Company N's property has 150 grains of hydrogen sulfide per 100 cubic feet.

- Pipelines and Storage Tanks - The oil moves from the treaters to the tank farm. Records are kept on the preventive maintenance to the pumps and pump motors (inspections and lubrications) and on tank cleaning and anode installation. The LACT meters are tested every 2 weeks. The LACT shipping pumps force oil into surge tanks with high level visual alarms.

- Water Treatment - Water from the free water knockout and treaters goes to skim tanks, to flotation cells, and then to a reinjection system. The tanks in the water treatment system have fiberglas bottoms which extend 2 inches up the sides to prevent oxidation. Sodium sulphite is added for oxygen. The skim tank has a pump which operates at 40 psi and high-low level arms. The flotation cells have valves which operate at 40 psi. The cells operate on intake at less than 30 psi to allow floculation. Gas from the flotation cells goes to gasline and water goes to a surge tank or, for untreated water, to a waste tank. All solid waste materials are hauled to a dump. The surge tanks are equipped with high-low level alarms. Pumps transport treated water to a filtration plant through epoxy-coated lines. The filtration plant is connected to the water injection plant and wells by concrete lined pipes.

Visit Number 4 - Company C's Crude Oil Production Facilities in Southern California.

Purpose - To observe operating equipment and procedures.

Personnel Contacted - Southern Division General Manager, Staff Engineer, Area Supervisors, and Area Foremen.

Observations - Both offshore and onshore production facilities were visited.

The offshore facility is a man-made island of 1.1 acres in water about 40 feet deep. The island has the capability for 128 wells (two cellars, A and B, with two lines of wells in each cellar and 34 well locations in each line).

- Production - Seventy-four wells are on stream. The field has not been drilled completely because of the drilling ban, since removed, and the need to obtain permits from State agencies. An average of 5500 barrels of oil and 4000 barrels of water per day are produced from eight zones ranging in slant depths from 3500 to 7000 feet. Artificial lift by gas and hydraulic pumping methods is used. Water from shallow onshore wells (capable of producing 20,000 barrels per day) is piped through 4-inch lines to the island. Some wet gas is produced and is recycled. Well tree valves are air open/spring close type. High-low pressure sensors are on the flow lines. The wells are shut down monthly to test meters and valves. Every 6 months, the subsurface control valves (two on each well, installed at depths of about 9 feet) are tested. Electric motors are used on the island but diesel engines are ready on standby basis.

- Pipelines - The pipelines to shore are on the ocean floor, coated, and cathodically protected. Gas is transferred by a 10-inch line and wet oil by a 12-inch line. Sensors can close and shut off lines at pressures outside the thresholds as follows:

Hydrocarbons	Pressure (psi)	
	Low	High
Gas	50	250
Oil	30	250

  Pigs are run in the oil lines every week.

- Safety - Figure A-4 is a safety instruction sheet supplied to all island visitors.

The onshore facility has the capability of 76 wells (two cellars, A and B, of two rows per cellar and 16 sites per row (at 6-foot spacing), plus 12 sites in the middle of the cellars).

- Production - A total of 68 wells have been drilled; 55 are on stream, 10 are used for water injection, and three are inactive. Production per day

ALL VISITING PERSONNEL

ALARM SIGNALS

FIRE	THREE (3) LONG BLASTS OF APPROXIMATELY 4-5 SECONDS EACH.
MAN OVERBOARD	THREE (3) SHORT BLASTS FOLLOWED BY TWO (2) LONG BLASTS.
ABANDON ISLAND	ONE (1) CONTINUOUS BLAST.

WHILE ON ISLAND - IF ANY OF THE ABOVE SIGNALS ARE HEARD, REPORT TO THE ISLAND OFFICE (LOCATED UPSTAIRS) FOR FURTHER DIRECTIONS.

THANK YOU,
ISLAND FOREMAN

Figure A-4. Safety Instruction Sheet

is 11,200 barrels of oil; 17,000 MCF of gas; and 5000 barrels (40 percent cut) of water. The production per day from another site (4200 barrels of oil, 2000-3000 barrels of salt water (30 to 40 percent water cut), and 3500 MCF of gas), is combined with production from the first site, then shipped to nearby treatment facilities. Of the 55 producing wells, five are water lift and 50 are gas lift or flowing. Production is from depths (vertical) of 2000 to 8000 feet, The crude is 25 to 30 degrees API. The surface casing extends down 1000 to 1500 feet. Below the surface casing 7-inch strings are run through the producing horizon or to the top of gravel pack.

Downhole, the gas lift and flowing wells have ball type safety valves which are dependable in operation and repeatable under test. These are installed 90 feet below the tubing head, are hydraulically operated (at 50 psi under the tubing pressure), and are removed by wire line. They can be operated manually or triggered by "Fire Eyes." Tests are conducted monthly and results of the tests, including removal of the valve, are documented. The gas lift wells have a check valve at the well head to prevent backflow from the annulus. The Christmas trees have pneumatic pressure-operated safety valves which, in the past, required considerable maintenance because the operator was pressure testing through the valves and weakening them. Test procedures have since been modified to bypass these valves during tests and this has improved the operational efficiency and life span of the valves. The flow lines are equipped with automatic valves. Injection wells have check valves to prevent backflow. They are locked into the tubing at a depth of 90 feet. Injection water (21,000 barrels per day) is obtained from outside sources. Headers have high-low shutdown equipment and alarms.

- Pipelines - Pipelines from another site transfer wet oil to this site's lines in 6-inch lines and gas in two lines of 6 and 8 inches. From this site to the treatment facilities, the pipelines are two low pressure gas lines of 8 and 10 inches at 180 psi each, one high pressure gas line of 8 inches at 300 psi, and a 12-inch wet oil line at 150 psi. These lines are about 4 years old. Pigs are run in the oil lines every 2 weeks. In the gas line, two ball pigs, with corrosion inhibitors between the two pigs, are run every 4 weeks. Power operated block valves are set into the lines leaving this site and at the entrance to the treatment plant to prevent backflow.

- Treatment Facilities - Although this site was not visited, it was stated that all separators and gas scrubbers have high-low pressure shutdown equipment and alarms.

Visit Number 5 - Company P's Texas Offices.

Purpose - To discuss operations in Southern California.

Personnel Contacted - Senior Vice President, Technical Manager of Environmental Control, Administrative Manager of Environmental Control, General Manager, and District Engineer.

Observations - Unable to arrange a mutually agreeable time to visit Company P's facilities, an interview was arranged in their Texas offices to discuss their operations. The information obtained is summarized as follows:

- Production - Company P produces about 20,000 barrels of oil and 180,000 barrels of water per day (90 percent water cut). The wells are on mechanical lift. The producing wells are old and the majority are in the Long Beach area. Since many are inside dikes and below sea level, pumps are available to remove rain water (it is pumped into the channel). Although the company representative did not discuss the details, Company P apparently had pumped oil into the channel because a shut-off valve, controlling the oil-water contact, failed to function. A preventive maintenance program is currently in operation on these and all pumps. Flow lines have been relocated away from dikes to avoid spills into water bodies.

- Pipelines - All lines over and under water are pressure tested. They are low stress, extra wall thickness steel. Cathodic protection devices are installed on underwater lines. The pipelines, as well as flow lines, are equipped with high-low pressure shut-in devices and quantity control meters (compares input and output of lines, then shuts down line if there is a sufficient mismatch). In addition, all lines are visually monitored from the dike banks.
- Treatment - API gravity separators have been enlarged to accommodate increased volume of produced water.

A.4.5 Trip Number 5 - Louisiana Gulf Coast Survey (2 through 10 December 1971)

Visit Number 1 - Company G's Louisiana Onshore Treatment Facility

Purpose - To observe onshore and offshore facilities and procedures.

Personnel Contacted - Assistant Division Manager; Area Manager; Field Production Superintendent, Main Pass Area; Field Foreman and Assistant Field Foreman, Onshore Treatment Facility.

Observations - A visit was made to several of Company G's onshore crude oil collocated treatment facilities. One facility treated and conditioned crude oil produced from State leases in the delta region. The other facility was for treating and conditioning OCS production from platforms in the Main Pass area. State lease production was produced from 49 wells; 25 are dual completion and 24 utilize gas-lift. The field contains 127 miles of flow lines, producing approximately 10,000 barrels of crude oil daily. The general configuration of the facility is depicted in Figure A-5. All relief valves and rupture discs are inspected semi-annually, the relief valves for operation and the rupture discs for corrosion conditions. Rupture discs are coated with cosmoline to deter corrosion from water. The valves are actuated by instrument gas derived from the low pressure vessels backed up by gas from high pressure vessels. The principal problems encountered at this facility, according to operating personnel, have been sand plugging and sand cutting.

The Main Pass Onshore Terminal conditions the fluid from the Main Pass OCS production pipeline prior to delivery to the pipeline. This facility is required to conform to USGS regulation. Figure A-6 depicts the configuration of the Main Pass Onshore Terminal. Approximately 50,000 barrels of crude oil and over 40,000 barrels of salt water are conditioned at this plant.

The salt water produced from State and OCS leases was emptied into a series of three salt water pits with oil skimmers prior to disposal into the Bay. The disposal point was enclosed by a floating boom encircling a large area as an additional precaution to contain any oil that might, under flooding of the pits, or other accidental circumstances, enter the Bay. The accumulated oil in the pits or Bay would be vacuumed as events required.

Several miscellaneous items of interest were revealed during discussions with company personnel. First, a formal spill contingency plan, ascribed to by the major oil production companies in the area, contains locations of various spill control equipment owned by the companies, names and phone numbers of each company's spill control and cleanup assistance personnel, and assignments of responsibilities to personnel during spill events. Second, the company has a fire-fighting school which consists of classroom and hands-on exercises using

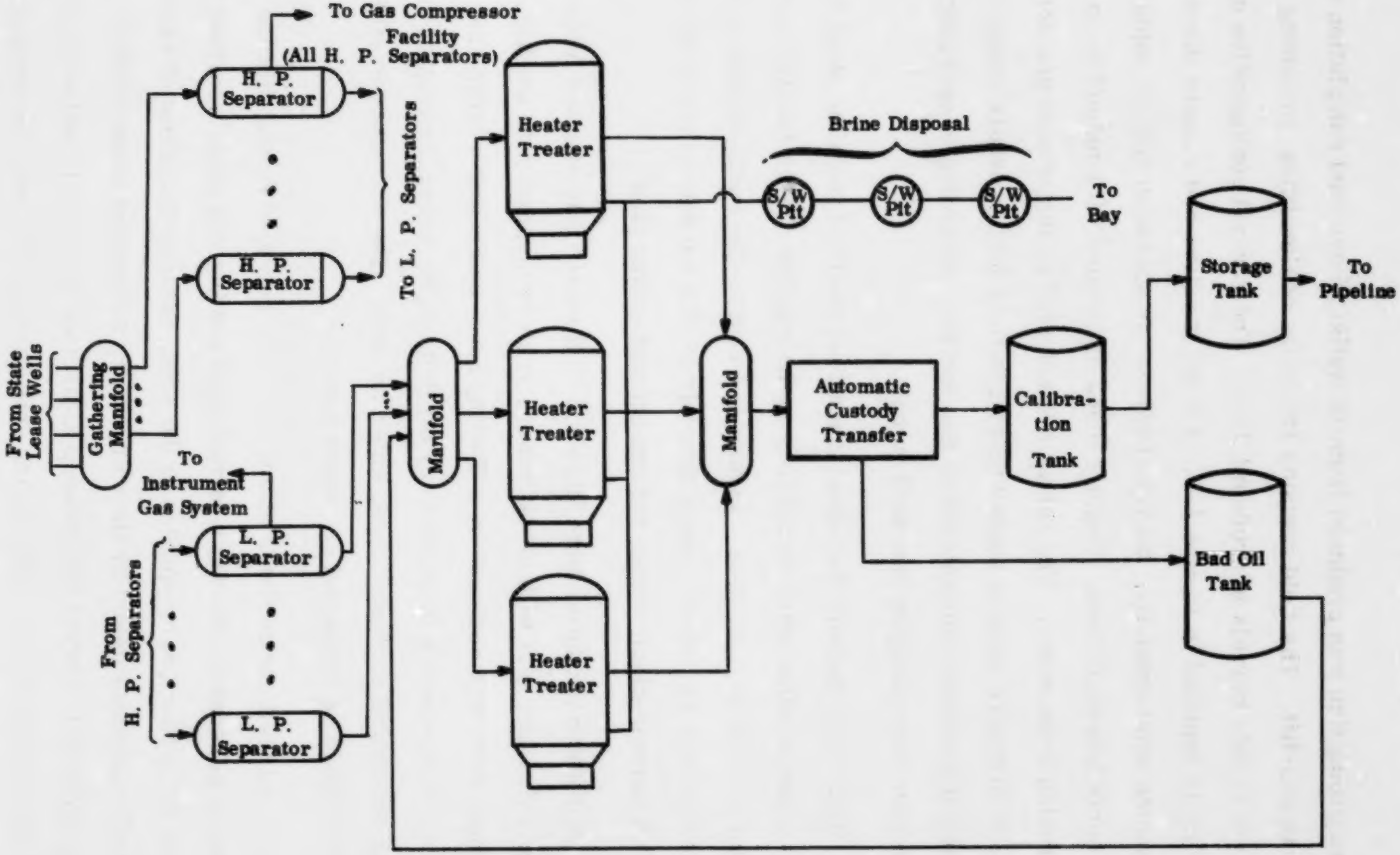

To Gas Compressor Facility (All H. P. Separators)
From State Lease Wells
Gathering Manifold
H. P. Separator
H. P. Separator
To L. P. Separators
To Instrument Gas System
From H. P. Separators
L. P. Separator
L. P. Separator
Manifold
Heater Treater
Heater Treater
Heater Treater
Brine Disposal
S/W Pit
S/W Pit
S/W Pit
To Bay
Manifold
Automatic Custody Transfer
Calibra-tion Tank
Storage Tank
To Pipeline
Bad Oil Tank

Figure A-5. Company G's Onshore State Lease Treatment Facility

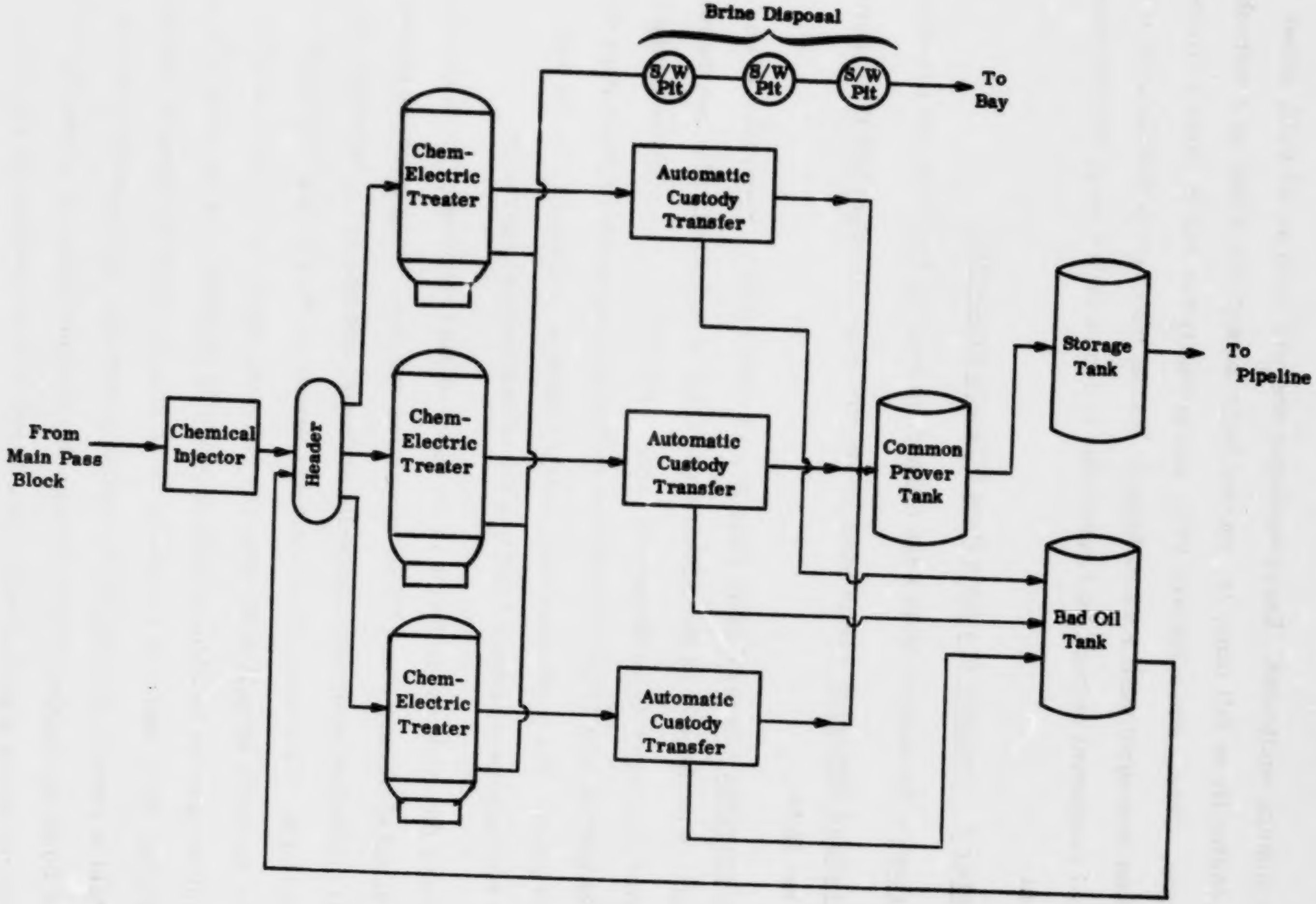

Brine Disposal
S/W Pit
S/W Pit
S/W Pit
To Bay
From Main Pass Block
Chemical Injector
Header
Chem-Electric Treater
Chem-Electric Treater
Chem-Electric Treater
Automatic Custody Transfer
Automatic Custody Transfer
Automatic Custody Transfer
Common Prover Tank
Storage Tank
To Pipeline
Bad Oil Tank

Figure A-6. OCS Production Onshore Terminal fire-fighting equipment. Every employee who will be in an oil field, either intermittently or full time, is required to go through the school as a refresher course. Third, since January 1971, this company has had in effect a "Hydrocarbon Noncontainment Failure Report" system which gives details as to cause, failed component or part, and corrective action taken for every noncontainment event.

Visit Number 2 - Company G's Main Pass Offshore Production

Purpose - To observe Main Pass offshore production facilities and procedures.

Personnel Contacted - Main Pass Production Superintendent and Field Foreman of two fields.

Observations - Several Main Pass Blocks were visited. Separation of gas and liquid is performed on the offshore platforms in both areas whereas the oil-salt water separation is performed at onshore facilities. The offshore production is transported by a 14-inch production gathering pipeline to the Main Pass Onshore Terminal. The production from another block is transported by the same pipeline to the onshore treatment facilities for oil-salt water separation.

One of the offshore platforms in the block visited consists of three structures connected by catwalks. These structures are crew living quarters platform, oil production equipment and wells platform, and gas and compressor equipment platform. This complex of platforms serves as the gas-liquid separation facility for the wells as well as the pipeline gathering point for all block satellite source well structures in addition to those wells on platform. In the event of a catastrophe, the complex is capable of being shut-in within 16 seconds, and the complete field is capable of being shut-in within 3 minutes. Approximately 90,000 barrels of liquid are produced daily through this complex from 107 producing wells. Twenty-seven injection wells are utilized in waterflooding the associated reservoirs. The configuration of this complex is shown in Figure A-7. Compliance and inspection reports in regard to USGS Orders 8 and 9 are summarily reviewed.

The other field is 22 years old and produces about 10,000 barrels of crude oil daily. The reservoirs have almost ideal water drive such that little water is produced with the oil until the well suddenly starts producing mostly water, at which time it is shut in. This field's production is from 75 strings which are primarily dual completion wells. Since the water depth in the field is about 12 feet and the Gulf floor in that area is soft silt, the flowlines are buried about 12 feet below the floor level. In contrast to the central pipeline gathering complex in the other field, the gas-liquid separation is performed on each individual platform and each platform produces into a production gathering line system. In turn, the gathering line system flows into headers to the pipeline for transportation to the onshore treatment facility. This pipeline also transports the Company's production from another Main Pass field. Problems experienced in the block are caused by sand plugging and sand cutting. Figure A-8 is a diagram of a typical configuration in this field.

Visit Number 3 - Company G's Bay Marchand Offshore Production and Onshore Treatment Facilities

Purpose - To observe facilities and procedures in the Bay Marchand area and older facility equipment.

Personnel Contacted - Area Manager, Field Product Supervisor, Structure Field and Structure Assistant Field Foremen, Structure Foreman, and Onshore Treatment Facility Foreman.

Observations - Two of the offshore facilities and an onshore treatment facility were visited in the Bay Marchand area. The two offshore facilities were similar. Each consists of three platform structures butted together instead of

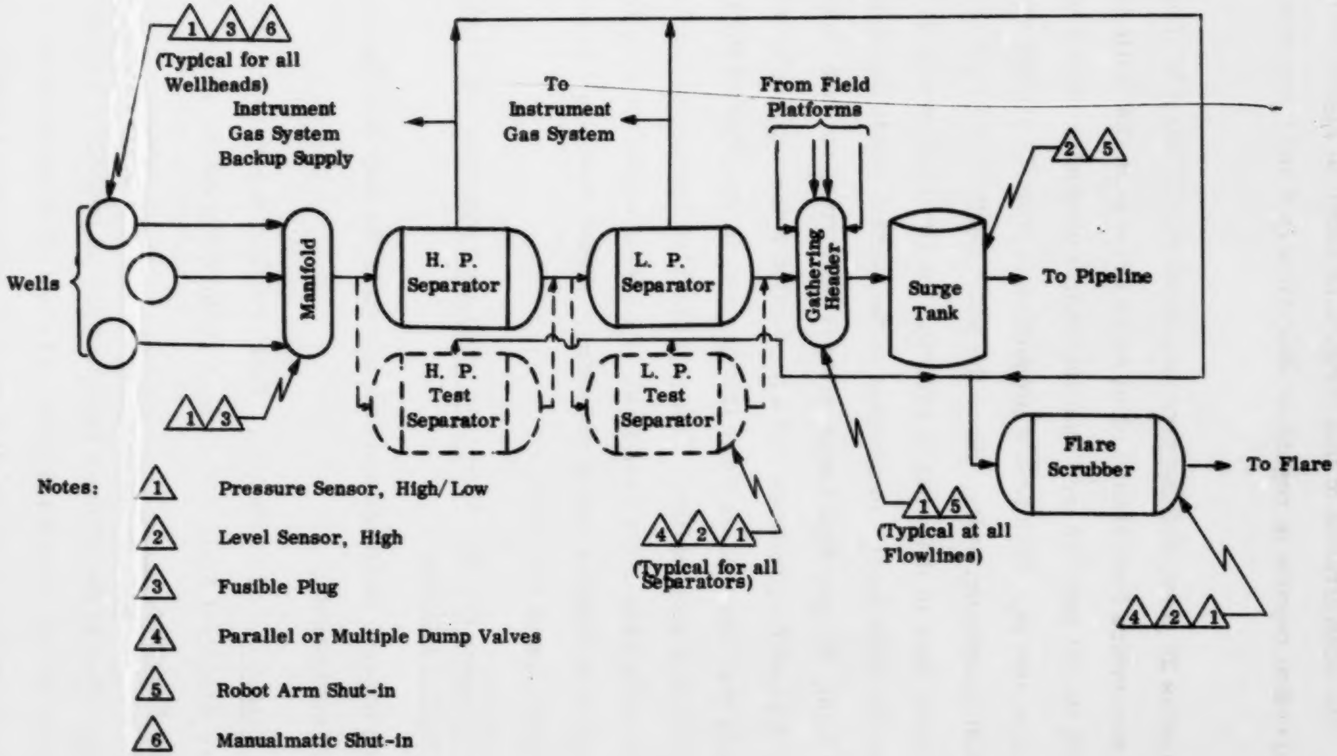

1 3 6
(Typical for all Wellheads)
Instrument Gas System Backup Supply
To Instrument Gas System
From Field Platforms
2 5
Wells
Manifold
H. P. Separator
L. P. Separator
Gathering Header
Surge Tank
To Pipeline
H. P. Test Separator
L. P. Test Separator
1 3
Flare Scrubber
To Flare
4 2 1
(Typical for all Separators)
1 5
(Typical at all Flowlines)
4 2 1
Notes:
1 Pressure Sensor, High/Low
2 Level Sensor, High
3 Fusible Plug
4 Parallel or Multiple Dump Valves
5 Robot Arm Shut-in
6 Manualmatic Shut-in

Figure A-7. Company G Main Pass Oil Production Platform

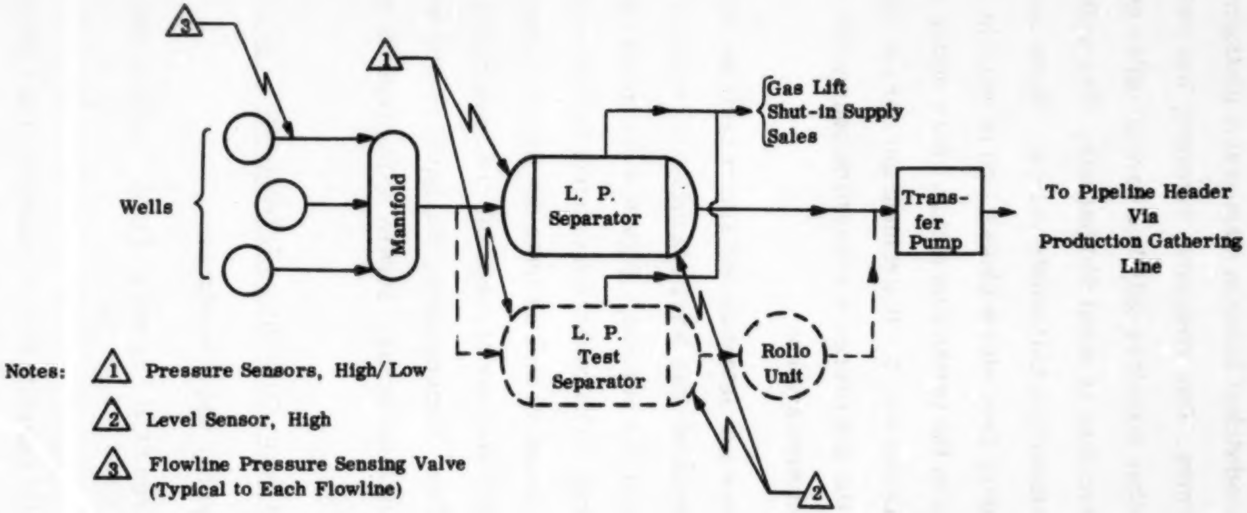

3
1
Gas Lift
Shut-in Supply
Sales
Wells
Manifold
L. P. Separator
Trans-fer Pump
To Pipeline Header Via Production Gathering Line
L. P. Test Separator
Rollo Unit
2
Notes:
1 Pressure Sensors, High/Low
2 Level Sensor, High
3 Flowline Pressure Sensing Valve (Typical to Each Flowline)

Figure A-8. Typical Main Pass Oil Production Platform being interconnected by catwalks. The configuration of both structures consists of a wellhead platform sandwiched between a separator platform and a compressor/surge tank platform. One structure, however, has living quarters for the crew, whereas the other structure only has several office quarters. The daily output of the one structure is about 700 barrels. The wells have surface-controlled (pneumatic) subsurface ball safety valves. Those wells having less than 100 psi tubing pressure have storm chokes tied by wire to the wellheads, instead of being installed in the production tubing. Such action has been approved by waiver of USGS OCS Order No. 5. Instrument gas for the various shut-in valves is obtained from the low pressure separation equipment with a backup gas source from the high pressure system.

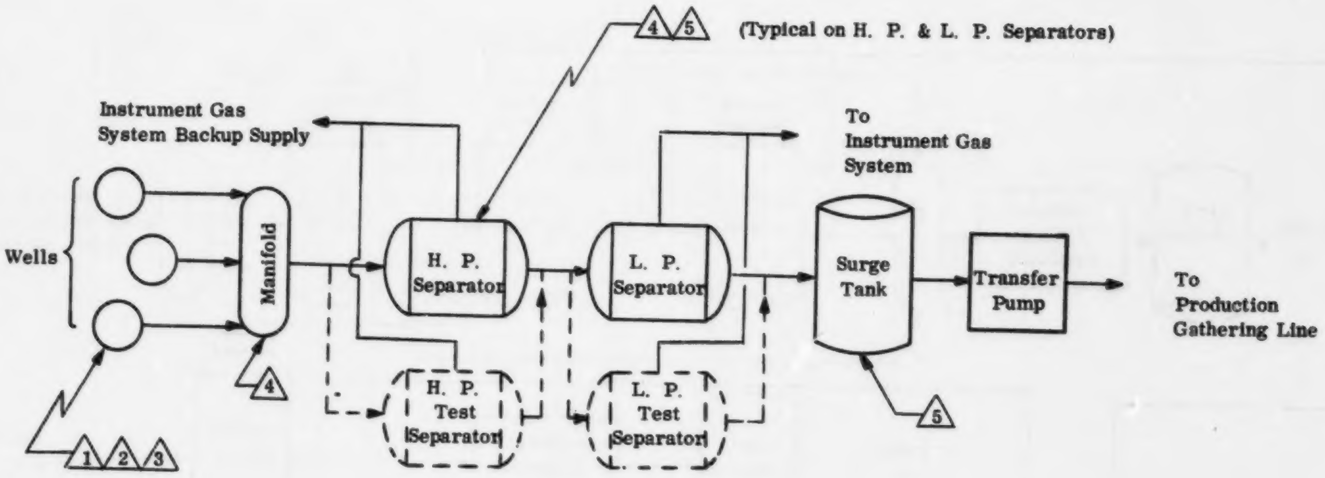
All enclosed buildings have gas detection and alarm systems which activate and cause shut-in if the combustible gas level reaches 60 percent of the USGS required maximum limit of 4.9 percent. Figure A-9 depicts the general configuration of the structures. The onshore treatment facility receives liquid from two state lease offshore areas as well as from the Bay Marchand and South Timbalier Areas. All four sources of crude oil are required to be segregated up to entry into the pipeline. Consequently, the liquid treatment facilities are duplicated in several equipment areas. Figure A-10 presents the configurations of this facility.

Visit Number 4 - Company H's South Timbalier's Offshore OCS Operations

Purpose - To observe facility and procedures.

Personnel Contacted - Area Staff Engineer, Field Foreman, and Field Maintenance Foreman.

Observations - The facility consists of five platforms interconnected by catwalks. The five platforms of the complex consist of two separation platforms, a gas compressor platform, a wellhead platform, and crew quarters platform. The



4
5
(Typical on H. P. & L. P. Separators)
Instrument Gas
System Backup Supply
To
Instrument Gas
System
Wells
Manifold
H. P.
Separator
L. P.
Separator
Surge
Tank
Transfer
Pump
To
Production
Gathering Line
4
H. P.
Test
Separator
L. P.
Test
Separator
5
1
2
3

Notes:
- △1 Surface-Controlled Subsurface Safety Valve (or Storm Choke Tied to Wellhead)
- △2 Manualmatics
- △3 Fusible Plug
- △4 Pressure Sensor, High/Low
- △5 Level Sensor, High

Figure A-9. Company G Bay Marchand Oil Production Platform

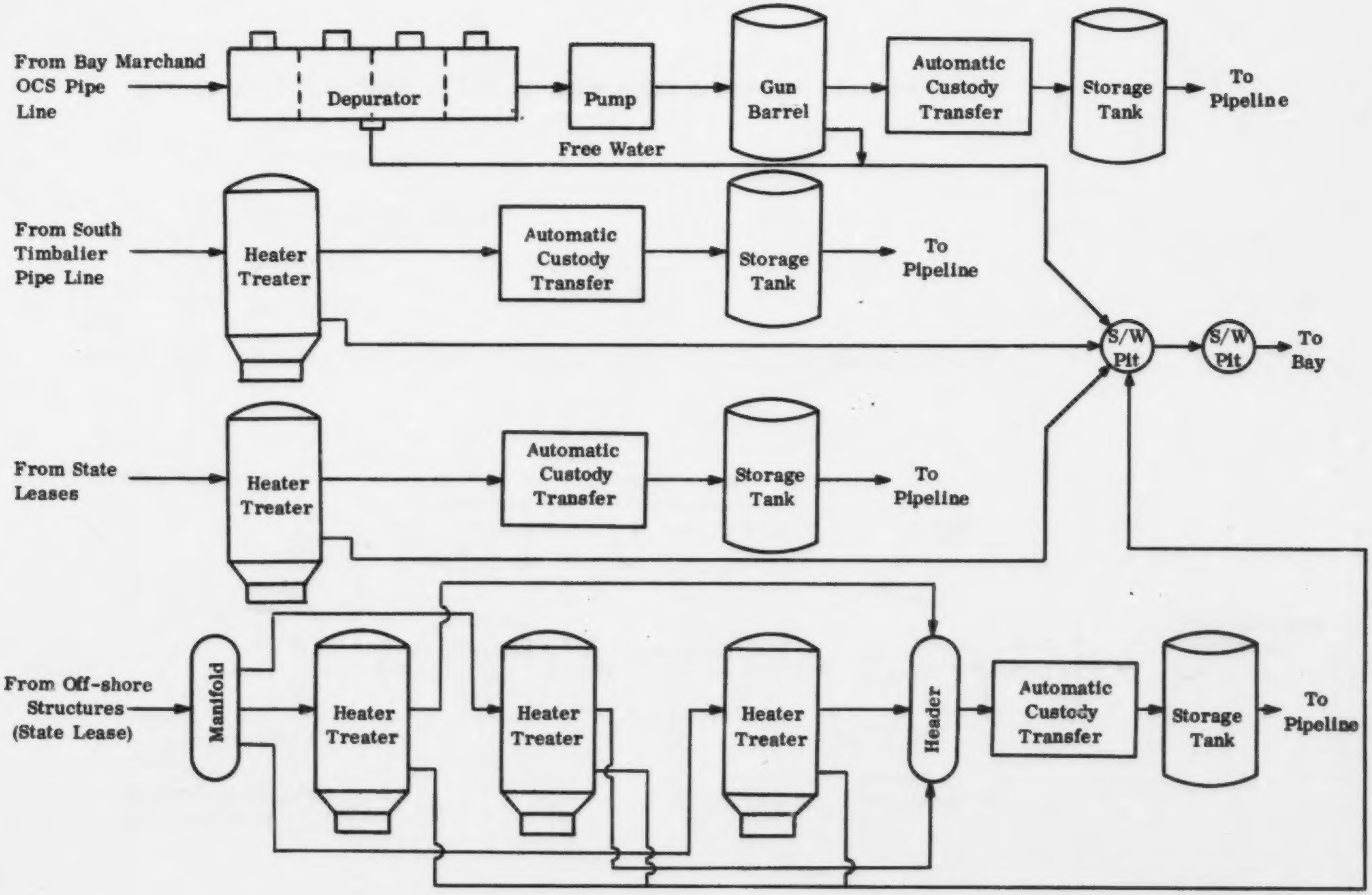

From Bay Marchand OCS Pipe Line
Depurator
Pump
Gun Barrel
Automatic Custody Transfer
Storage Tank
To Pipeline
Free Water
From South Timbalier Pipe Line
Heater Treater
Automatic Custody Transfer
Storage Tank
To Pipeline
S/W Pit
S/W Pit
To Bay
From State Leases
Heater Treater
Automatic Custody Transfer
Storage Tank
To Pipeline
From Off-shore Structures (State Lease)
Manifold
Heater Treater
Heater Treater
Heater Treater
Header
Automatic Custody Transfer
Storage Tank
To Pipeline

Figure A-10. Company G's Treatment Facility field produces about 40,000 barrels of crude oil daily from most of 190 source wells. After gas-fluid separation at the facility, the crude oil is transported by pipeline to the onshore treatment facility. Instrument gas is supplied from the separation equipment. The instrument gas distribution system is composed of nylon plastic tubing rated for 2500 psi and 168° melting point. This tubing is used instead of fusible plugs, except at the wellheads and manifolds. The pressure vessel equipment was configured to vent to a flare system which contained a scrubber. The separation equipment consists of high pressure separators with two dump valves (normal and high level), low pressure separators with three dump valves (normal, high level, and high-high level), and a free water knockout. Figure A-11 depicts the general configuration of the facility. During the visit, a valve company maintenance man stationed at the complex was contacted. He provided some insight to the failure modes of several valve types that he maintained. It was also learned that Company H has a failure and operating/maintenance error data system.

Visit Number 5 - Company B's New Orleans Office Visit

Purpose - To discuss their data program.

Personnel Contacted - District Production Superintendent and Special Staff Engineer.

Observations - Company B was contacted to discuss their data program. The Special Staff Engineer had recently transferred to the Gulf Coast area from West Texas. In West Texas he was instrumental in the development and implementation of Company B's initial formal preventive maintenance and data collection program. This pilot program has been very successful, and he is now working on a similar program for Company B's Gulf Coast operations. During the meeting, the opportunity was afforded to see samples of the preventive maintenance schedules and copies of the associated checklists and failure reports currently in use in West Texas.

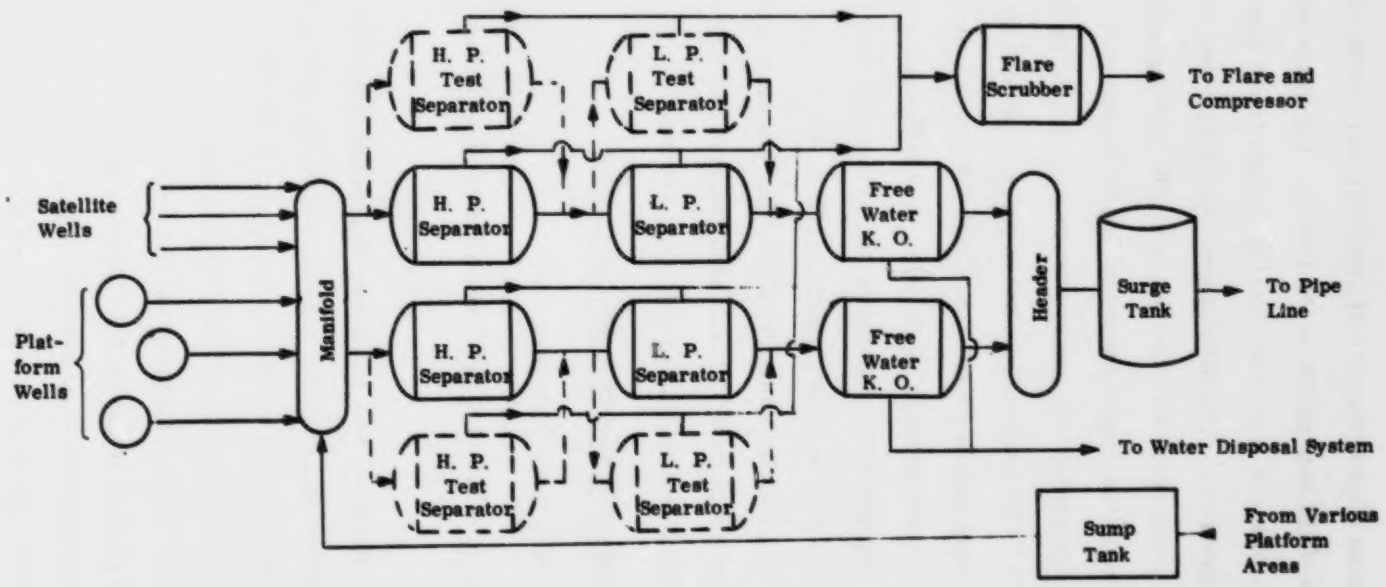

Satellite Wells
Plat-form Wells
Manifold
H. P. Test Separator
L. P. Test Separator
H. P. Separator
L. P. Separator
H. P. Separator
L. P. Separator
H. P. Test Separator
L. P. Test Separator
Flare Scrubber
To Flare and Compressor
Free Water K. O.
Free Water K. O.
Header
Surge Tank
To Pipe Line
To Water Disposal System
Sump Tank
From Various Platform Areas

Figure A-11. Company H South Timbalier Oil Production Facility

A.4.6 Trip Number 6 - Continuation of Louisiana Data and Field Survey (7 through 18 January 1972)

Visit Number 1 - USGS New Orleans District

Purpose - To scope the data available in the District files.

Personnel Contacted - Bert Mullins, New Orleans District Supervisor and Gene Marsh of the USGS Regional Office.

Observations - Items of interest obtained during the visit were:

- The Items of Non-Compliance (INCS), Potential Items of Non-Compliance (PINCS), and the USGS inspection forms were designed by a management information section in the USGS Water Resources Division.
- A copy of a speech given by Bob Evans to the oil industry at a meeting in Houston, Texas, last fall was obtained. It contained statistics that resulted from the USGS initial analysis of their inspection results. These statistics gave numbers of check valves, subsurface valves, pressure sensor pilots tested, and the numbers failing during the inspections. In addition, statistics were given in relation to blowouts during drilling and production operations.
- Mr. Mullins suggested a report, "Environmental Quality, Second Annual Report," which he believes is worth reviewing.
- A tabulation of the various reports and documents at the New Orleans District Office, which would be of interest in relation to the project, is given in Table A-1.

Table A-1. Reports and Documents, New Orleans District Office

Report/Document	Quantity
Pollution (Spill) Reports	3,500
Production Inspection Reports (OCS-3)	550
Drilling Inspection Reports (OCS-2)	300+
Accident Reports	480
Semi-annual Industry Inspection Records (1 January - 1 July 1971)	15,000 pages
Configuration Schematics	50

A review of spill reports indicate that they are sources of equipment failure information which is of value to this study. Many of these failures are not detailed in the monthly summary since they are spills of one barrel or less.

Visit Number 2 - Company J's Platform on the OCS in the Grand Isle Area

Purpose - To observe offshore operations and procedures.

Personnel Contacted - Petroleum Engineer, Platform Foreman, and Operator.

Observations - This platform serves as the gas-liquid separation point for various well structures in the West Delta as well as other Grand Isle structures. Altogether 11 crude oil gathering lines and a number of gas gathering lines from the various blocks enter this platform, varying in size from 6 to 16 inches. The daily production through this platform consists of approximately 85,000 barrels of liquid (65,000 of crude oil and 20,000 of salt water). The platform also serves as the metering point for sales gas. The complex consists of the following five platform structures:

1. Quarters, Control, and Electrical Generator Platform
2. Riser, Pig Trap, and Major Manifold Platform
3. Gas/Liquid Separators, Scrubbers, and Surge Tank Platform
4. Pumping Platform
5. Compressor Platform

The liquid is transported by a 20-inch pipeline to Grand Isle onshore treatment facilities for further treatment prior to sales. This complex is being converted to full automation.

There are 285 wells which produce into this complex, most being dual completion wells. The gas-lift wells have surface-controlled subsurface safety valves, whereas the pressure wells have velocity-actuated storm chokes. Spring return valves are used on all wellheads.

A dual supply of instrument gas is in use on this platform; an actuator supply system supplies all the operators, and a gas instrument supply system supplies the rest of the shutdown system. Each supply system is capable of backing up the other. The gas is derived from a 16-inch gas line from another Grand Isle block. It is scrubbed and filtered prior to use in the dual system. Natural gas, instead of inert gas, is used in the dual system for economic reasons. The daily quantity of gas used for these supplies is about 84,000 cubic feet. Consequently, it would be costly to install special compressors for the dual system supply and supply the quantity of inert gas that would be required if inert gas, rather than the readily available natural gas, was used.

The operation is monitored and controlled through a panel on the crew structure by electrical signals at the various sensors. The enclosed structures have both ultraviolet monitoring and gas sniffer detection. The ultraviolet system will set off an alarm but will not activate fire equipment since it is sensitive to water reflections from the deck. The complex is operated by a foreman and two operators, and hourly rounds are made on the platforms.

The separation platform consists of a high pressure gas scrubber whose liquid is dumped into the primary separators. The incoming oil line feeds into two primary separator-scrubber combinations. The primary scrubbers and separators have two dump valves, one for throttling control and the other for surge dumping. If a high level occurs in one primary separator, the oil is automatically switched to the other, the same being true in relation to the scrubbers. The oil then goes through three intermediate separators into three surge tanks. The levels on the surge tanks, in turn, control the number and speed of the transfer pump motors required to maintain the pumping capacity for the surge tanks. These pumps can handle 300 percent of the normal flow capacity of the complex.

The sump system consists of a drainage sump tank with a high level indicator and dual pumps which pump the drainage into the surge tanks. Oil drainage from the transfer pump bearings is pumped into the pipeline. In the event of problems in the primary separators downstream, all production can be bypassed back to the pipeline to Grand Isle. Oil gathered in the pig traps is channeled back into the gathering line instead of the sump system. The main problem experienced at the complex is sand-cutting of valve trim, primarily on the dump valves. Consequently, an annual inspection/replacement of valve trim is done as a preventive maintenance program. The schematic diagram of this complex is presented in Figure A-12.

Visit Number 3 - USGS Districts 1 and 2 - Lafayette, Louisiana

Purpose - To determine the quantities of data of various types.

Personnel Contacted -

District No. 1: George Kinsel, Engineer; Robert Darrow, Assistant Engineer; Al Davis, Chief Production Engineering Technician

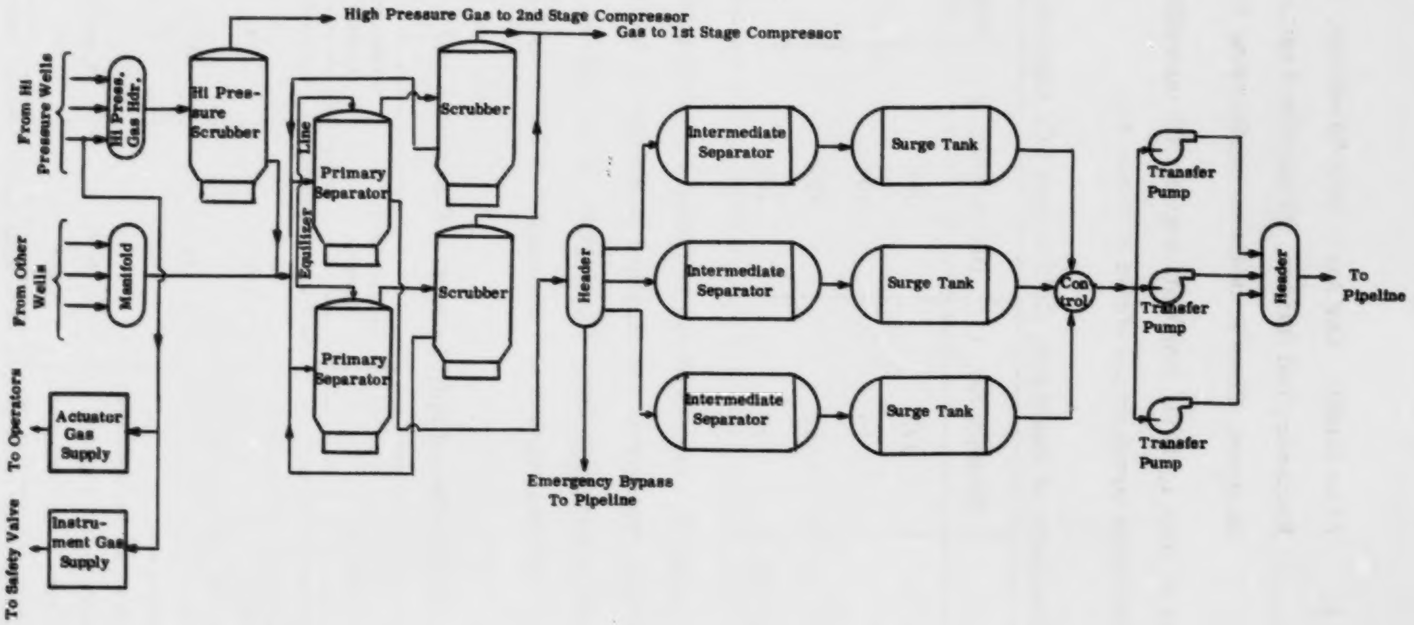

High Pressure Gas to 2nd Stage Compressor
Gas to 1st Stage Compressor
From Hi Pressure Wells
Hi Press. Gas Hdr.
Hi Pressure Scrubber
From Other Wells
Manifold
To Operators
Actuator Gas Supply
To Safety Valve
Instrument Gas Supply
Line
Equilizer
Primary Separator
Primary Separator
Scrubber
Scrubber
Header
Emergency Bypass To Pipeline
Intermediate Separator
Intermediate Separator
Intermediate Separator
Surge Tank
Surge Tank
Surge Tank
Control
Transfer Pump
Transfer Pump
Transfer Pump
Header
To Pipeline

Figure A-12. Simplified Schematic of Company J Grand Isle Platform

District No. 2: Elmo Hubble, Engineer; Jack Sandridge, Assistant Engineer; Ted Hudson, Production Engineer; Derwood Simpson, Chief Production Engineering Technician

Observations - As of June 1, 1971, The Gulf Region OCS operations had jurisdiction over the facilities summarized shown in Table A-2.

Table A-2. Summary of Facilities, Gulf Region OCS Operation

Facilities	District No. 1	District No. 2	New Orleans
Platforms	372	955	479
Single Wells	219	496	122
Multiple Wells	134	357	321
Production Platforms	29	102	36

In addition to the quantities of data shown in Table A-2, well status summaries are available. These summaries are attached to the end of the USGS monthly summaries and are available in their Washington, D. C. offices. A tabulation of the quantities of various reports and documents at Districts 1 and 2 is given in Table A-3.

Table A-3. Tabulation of Spill Reports - Districts 1 and 2

Report/Document	District No. 1 Quantity	District No. 2 Quantity
Pollution (Spill) Reports	One 3-inch Ringbinder	50/month
Production Inspection Reports (OCS-3)	338*	904
Drilling Inspection Reports (OCS-2)	98	114
Accident Reports	12**	25
Semi-annual Industry Inspection Records (1 Jan. - 1 July 1971)	4,400***	15,600***
Storm Chokes (12-month period)	4,400	26,000

*From December 1971 to present, not including random "drop-in" inspections.

**Seven were major incidents. The first was dated May 14, 1971.

***For the first 6-month period. The next 6-month submittal which will be approximately of equivalent quantities was due after 1 February 1972.

Visit Number 4 - Office Visits to Companies B, H, and K and USGS Regional Office

Purpose - To determine the utility of Company H's data to the study, to discuss Company K's maintenance records, to further discuss data with Company B, and to discuss with the USGS various topics of interest.

Personnel Contacted - Area Staff Engineer of Company H, Assistant Drilling and Production Manager of Company K, Special Staff Engineer of Company B, Robert Evans (Regional Oil and Gas Supervisor), and Gene Marsh of the USGS.

Observations - The purpose of the visit to Company H was to determine if their data would be useful to the study. However, the data was in response to OCS Orders 8 and 9 and was already available through the USGS.

Company K's contact said that they did not keep failure or maintenance records. They determine the adequacy of various brands of equipment by interviewing their field personnel on their experience.

The letter to the environmental coordinator requesting failure and maintenance data was discussed with the Company B contact. He felt he would be contacted concerning the letter, but expressed the opinion that getting the failure and maintenance data from Company B would be difficult.

Visit Number 5 - Company L's South Pass Facilities

Purpose - To observe facilities and procedures.

Personnel Contacted - Superintendent, South Pass; Chemical Engineer, Field Foreman, South Pass Treatment Facility; Maintenance Foreman, South Pass OCS Production.

Observations - The production from this facility is approximately 85,000 barrels of crude oil daily produced from 250 dual and 300 single completion wells. The wells are individually configured on platforms, with the produced well streams flowing to gas-liquid separation platforms and then transported to a freewater knockout (FWKO) platform. After the offshore separation processes, the crude oil and water are separately pipelined to onshore facilities where the crude oil is further gas-oil separated, heated, further water-oil separated, reheated, allowed to settle, then transferred and sold to a pipeline company or to barges. The problems presently experienced in this operation have been external corrosion on risers and plugging of bubbler valves in the water treatment facilities. The oil spills occuring at the onshore facility have been at the barge loading facility. Consequently, an automatic safety shut-in system with full-time manned backup is enforced. Riser corrosion as well as corrosion at wellheads and flowlines have been surveyed by X-ray to allow a maintenance program to be set up. Sections of rubber-encased risers have been installed in the splash zone areas of the flowlines to alleviate corrosion at these points.

While discussing the records for the USGS and Company L, it was learned that job request records were filed at this facility for the period since March 1970. The job request records contain the equipment involved, trouble indicated, date, disposition, and related remarks. Approximately 15,000 of these records are available and accumulate at about 500 to 600 per month. This does not include some repair actions which are accomplished without a formal job request.

Initially, the team was shown the onshore facility by the field foreman of the treatment facility. It consists of two identical crude oil and salt water treatment systems, one for OCS production and the other for State lease production. Therefore, only one system will be described. The emulsified crude from offshore is piped through a low pressure separator to further separate the gas from the crude oil. The temperature of crude oil is raised 15 degrees by steam heat, and the crude oil is transported to a surge tank where the water emulsion is sent to the water treatment system. The crude oil is then passed through a heat exchanger to be heated to 120°F before being transported to a settling tank (gun barrel). The water recovered at the settling tank is also sent to the water treatment system. The crude oil is then piped to a LACT unit which consists of a prover tank, meter, filter, BS&W probe-type monitor, and sampling tank. The sampling tank oil is checked weekly to determine what corrections must be made to the API gravity and BS&W content of the oil sold during the week.

The produced salt water and sand from offshore, between 12,800 and 17,000 barrels per day, is routed to the water treatment facility along with water recovered from the onshore surge and gun barrel tanks at the oil treatment system. In addition, any emergency-diverted oil from the FWKO is diverted to the water lines and transported to the onshore water treatment facility. Initially, the produced water is diverted into two settling tanks. Each settling tank outlet is diverted to two flotation cells prior to disposing clean water into the bay. Recovered oil from the settling tanks and flotation cells is routed to the separator at the crude oil treatment facility. Calcium deposits on the bubbling valves and diaphragm of the flotation cells present a plugging problem which reduces the efficiency of the water cleaning plant. A desander is also under test and evaluation for potential use in reservoir pressure maintenance.

The maintenance foreman for South Pass OCS production showed the team a platform typical of the gas-liquid separation platforms in the field. It is positioned in 60 feet of water. This structure provides the gas-liquid separation for 40 wells. The wells have pressure differential-activated storm chokes. The wellheads and flowlines are cathodically protected. The production from these wells enters the platform through a manifold equipped with high/low pressure sensors. The flow then enters high, intermediate, and low gas-liquid separators. The gas is transported to the onshore compressor facility while the liquid is transported to a FWKO platform. In addition to the three production separators on the platform, there are three test separators (high, intermediate, and low). All separators had high-level well shut-in capability. The separators are also equipped with throttling and surge dump valves, as are the FWKO vessels. The FWKO vessels divert the crude oil into water and sand pipeline to shore in the event of a high-level condition in the vessel (see Figure A-13). Both the gas-liquid and the FWKO vessels are protected against corrosion by rectified cathodic protection systems.

A simplified configuration schematic of the production system in South Pass and the associated onshore facility is depicted in Figure A-13.

A.4.7 Trip Number 7 - Company D's New Orleans Division Office (15 through 18 August 1972)

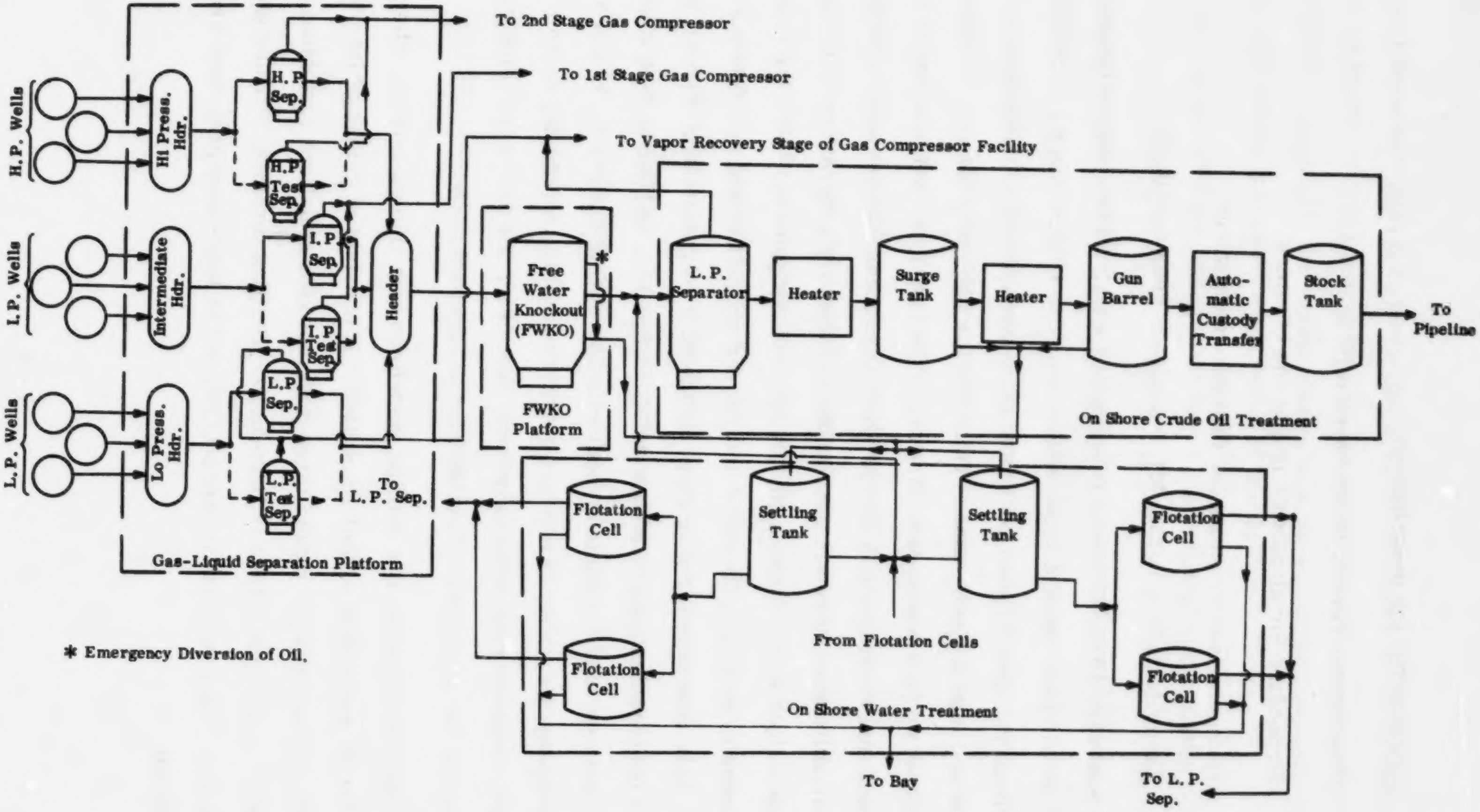
Visit Number 1 - Company D's Office

Purpose - To view Company D's approach to crude oil spill prevention and collect data.

Personnel Contacted - Environmental Control Engineer, Operations Engineering Advisor, Task Force Engineer (Failure Reporting), Offshore Area Production Superintendent, Associate Mechanical Engineer, Division Drilling Engineer, two Division Computer Science Supervisors, and two Corporate Management Science Engineers.

Observations - The team was presented with an overview of their approach to spill prevention. The presentation lasted for the duration of this trip, consequently, was the only facility planned for visitation. The presentation consisted of descriptions of:

- Failure data collection and analysis for safety devices
- Failure data collection and analysis for storm chokes
- Safety device inventory system
- Blowout prevention school


H. P. Wells
I. P. Wells
L. P. Wells
Hi Press. Hdr.
Intermediate Hdr.
Lo Press. Hdr.
H. P. Sep.
H. P. Test Sep.
I. P. Sep.
I. P. Test Sep.
L. P. Sep.
L. P. Test Sep.
Header
To L. P. Sep.
Gas-Liquid Separation Platform
To 2nd Stage Gas Compressor
To 1st Stage Gas Compressor
To Vapor Recovery Stage of Gas Compressor Facility
Free Water Knockout (FWKO)
*
FWKO Platform
L. P. Separator
Heater
Surge Tank
Heater
Gun Barrel
Automatic Custody Transfer
Stock Tank
To Pipeline
On Shore Crude Oil Treatment
Flotation Cell
Settling Tank
Settling Tank
Flotation Cell
Flotation Cell
Flotation Cell
From Flotation Cells
On Shore Water Treatment
To Bay
To L. P. Sep.

* Emergency Diversion of Oil.

Figure A-13. Company L's South Pass Production Operation

- Documented job descriptions
- Procedures related to workover efforts
- Procedure for ultrasonic inspection of piping
- Computerized program for dynamic maintenance
- Computerized program for redundancy considerations.

In February 1972, Company D organized a task force group to update its data acquisition and control system to enhance its failure analysis capability and collect the detailed data needed to allow them to utilize computerized reliability and maintenance programs. This effort is presently directed to safety devices and subsurface equipment. However, the task force will eventually address all functional equipments in this production process. In conjunction with the failure data collection, they are developing an inventory program to determine the populations of the various equipments and components. With the failure data and inventory systems, they will analyze the reliability and maintenance pertaining to their operations to give them a capability to recommend the best items for various applications, offshore safety equipment, and subsurface equipment selections, and complete computerization of OCS Orders 5, 8, and 9. Copies of Company D's safety device and storm choke failure reports, inventory worksheet, and computer runs were examined. However, the data are preliminary and contain too few entries to utilize for the present study.

A copy of Company D's drilling guidelines was also examined. They have had a blowout prevention school since 1965. It consists of 2 days of lecture and 1 day for each attendee to handle three different kick situations simulated in a well into which a nitrogen bubble is introduced. Drilling foremen, drilling engineers, tool pushers, and contract personnel involved in long-term programs are sent to the school.

Several computerized offshore facilities were discussed and a computer run from 1 day of operation was brought in. An example of how the computerized operation lent itself as backup to the safety system was shown by the computer run as an incidental fallout from computerization of the field.

The procedure followed, when a workover rig is brought to a platform, was explained in relation to the wells and the platform. For example, these wells not under the rig's substructure will be allowed to continue to produce after inspection of their storm chokes. Downhole plugs are put in the wells under the rig's substructure. A complete inspection of the safety equipment is made. A judgement is made by the platform supervisor after discussion with the drilling supervisor as to whether it is necessary to shut-in process equipment and fill tanks with water. Another factor brought out during the discussion of production was ultrasonic inspection of high pressure piping. It was learned that the inspection frequency is increased if H_2S or CO_2 are present. Whenever new storm chokes are installed on new wells or workovers, the chokes will be inspected within 30 days. A manual of detailed job descriptions and personnel requirements was shown. Computerized maintenance optimization strategies and techniques were explained, followed by a walk-through of two examples based on actual data from several refinery plants. An explanation was given as to the extension and applicability of these programs to production facilities once the production data system was in an implementable form.

APPENDIX B

SUBSYSTEM DESCRIPTIONS

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APPENDIX B

SUBSYSTEM DESCRIPTIONS

B.1 INTRODUCTORY SUMMARY

This appendix supplements the system and subsystem descriptions presented in Volume I. providing more detail to the descriptions and describing the functions in the equipment within each subsystem. It is included to provide comprehensive description of petroleum systems. The information was developed from field surveys, discussions with oil field personnel, and study of texts, catalogs, and other petroleum system literature to provide an analytical framework for data collection (Appendix D) and analysis (Appendix E). To facilitate the use of this appendix, Figure B-1 presents the systems and subsystems cross-referenced to their appropriate block diagrams and functional details.

B.2 DRILLING SYSTEM

The Drilling System subsystems are given in Figure B-2 to allow orientation without referring to Volume I. The Drilling System is broken down into six subsystems -- Well, Prime Power, Hoisting and Rotating, Mud, Drilling String, and Blowout Preventer.

B.2.1 Well Subsystem

The Well Subsystem (Figure B-3) consists of equipment necessary for drilling operations and provides protection from downhole natural phenomena, and protects the fresh water strata. Sealing the casing to the hole walls is another function. The casing heads provide a base upon which surface safety equipment and mud return control equipment can be mounted and become a permanent part of the well. Consequently, the required functional equipment are the hole, casing strings, casing heads, and cement. The depth, size, and strength of the casings must be established from the anticipated pressures and formation strengths downhole; the collapse, burst, and tensile requirements of the casing string; and the future operational loads which may be imposed upon the casing. The casing cement should be pressure tested at strategic intervals when approaching abnormal pressure zones and drilling in them. The casing heads should be pressure rated with consideration of maximum anticipated bottom hole pressure (BHP).

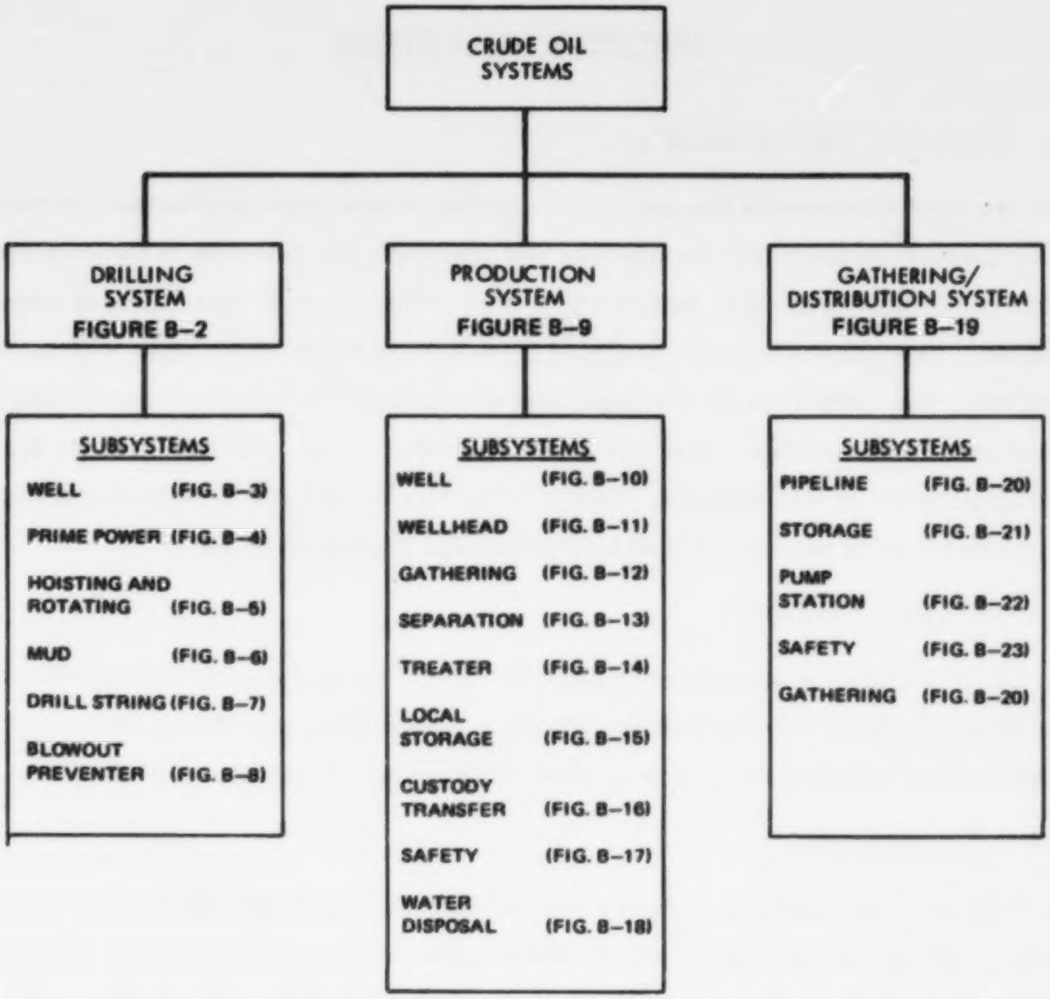
CRUDE OIL SYSTEMS
DRILLING SYSTEM FIGURE B–2
PRODUCTION SYSTEM FIGURE B–9
GATHERING/ DISTRIBUTION SYSTEM FIGURE B–19
SUBSYSTEMS
WELL (FIG. B–3)
PRIME POWER (FIG. B–4)
HOISTING AND ROTATING (FIG. B–5)
MUD (FIG. B–6)
DRILL STRING (FIG. B–7)
BLOWOUT PREVENTER (FIG. B–8)
SUBSYSTEMS
WELL (FIG. B–10)
WELLHEAD (FIG. B–11)
GATHERING (FIG. B–12)
SEPARATION (FIG. B–13)
TREATER (FIG. B–14)
LOCAL STORAGE (FIG. B–15)
CUSTODY TRANSFER (FIG. B–16)
SAFETY (FIG. B–17)
WATER DISPOSAL (FIG. B–18)
SUBSYSTEMS
PIPELINE (FIG. B–20)
STORAGE (FIG. B–21)
PUMP STATION (FIG. B–22)
SAFETY (FIG. B–23)
GATHERING (FIG. B–20)

Figure B-1. Elements of Crude Oil Systems

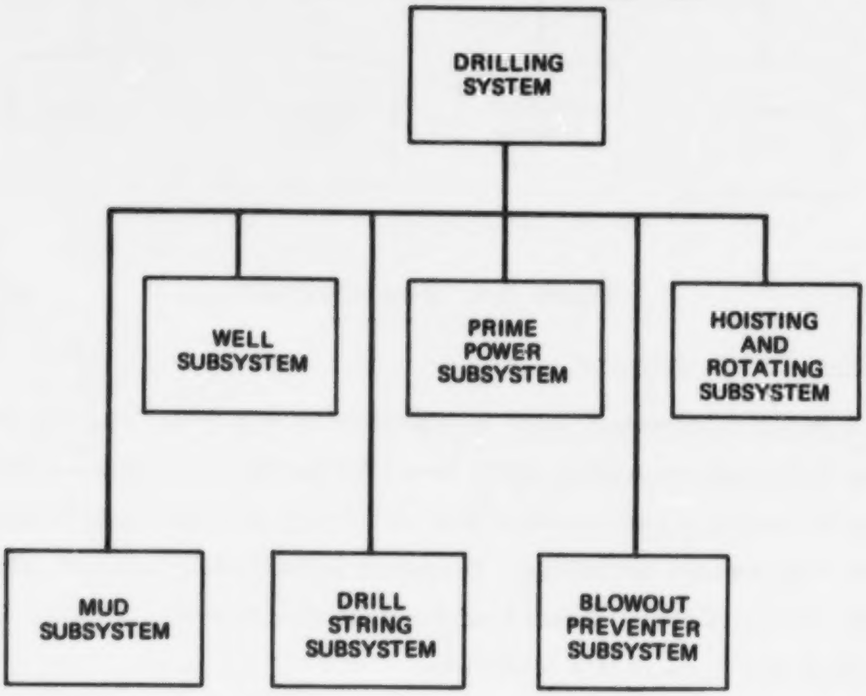
DRILLING SYSTEM
WELL SUBSYSTEM
PRIME POWER SUBSYSTEM
HOISTING AND ROTATING SUBSYSTEM
MUD SUBSYSTEM
DRILL STRING SUBSYSTEM
BLOWOUT PREVENTER SUBSYSTEM

Figure B-2. Drilling System

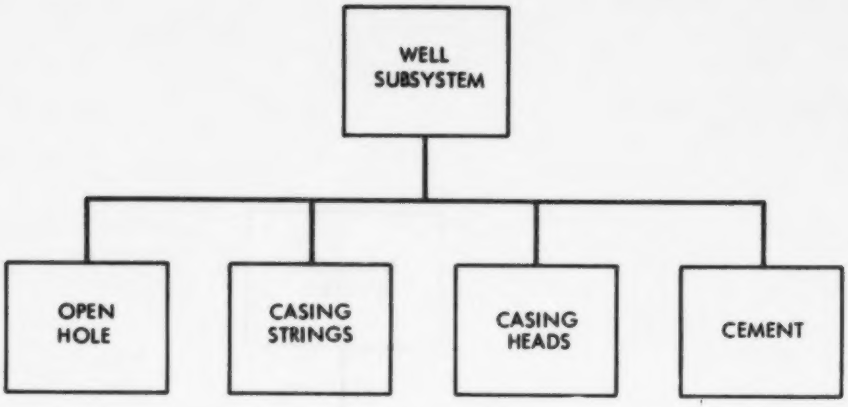
WELL SUBSYSTEM
OPEN HOLE
CASING STRINGS
CASING HEADS
CEMENT

Figure B-3. Well Subsystem

B.2.2 Prime Power Subsystem

The Prime Power Subsystem (Figure B-4) provides power to the hoisting, rotating, and circulating equipment, as well as utility power for peripheral uses and lights. The bulk of the supplied power is used in either mud circulating and rotating or hoisting, which are not usually simultaneous operations. The power is provided by internal combustion engines or electric motors. Power transfer (both electrical and mechanical) and control equipment are also parts of this subsystem.

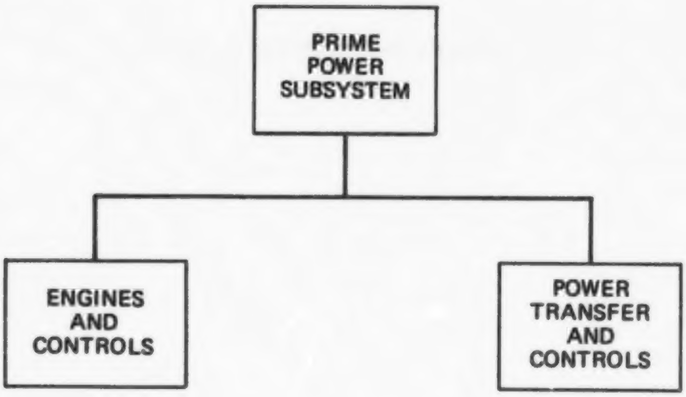
PRIME POWER SUBSYSTEM
ENGINES AND CONTROLS
POWER TRANSFER AND CONTROLS

Figure B-4. Prime Power Subsystem

B.2.3 Hoisting and Rotating Subsystem

The Hoisting and Rotating Subsystem (Figure B-5) contains the equipment necessary to raise and lower the drill string and to impart the rotary action that accomplishes the drilling. The equipment includes the physical substructure over the well, which supports the derrick that provides the vertical clearance for drill string trips; the hoists (draw works) that provide the control (clutches, engine throttles, sprockets, et cetera) for the driller; the Rotary Table, which provides for collets (slips and drive bushings) and rotates the drill string; and other related items shown in Figure B-5.

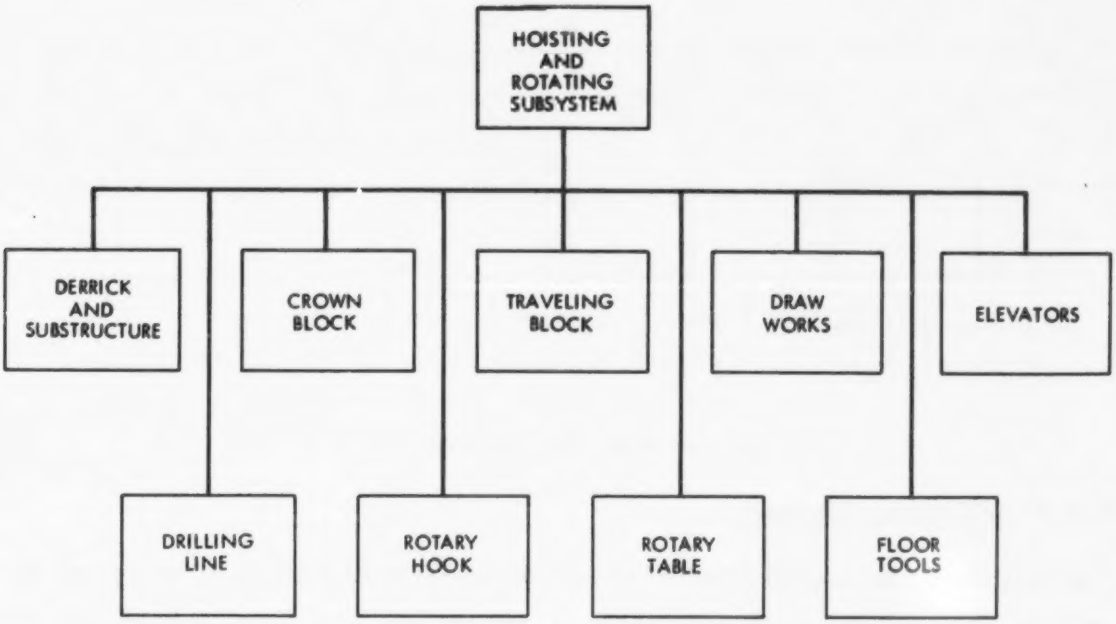
HOISTING AND ROTATING SUBSYSTEM
DERRICK AND SUBSTRUCTURE
CROWN BLOCK
TRAVELING BLOCK
DRAW WORKS
ELEVATORS
DRILLING LINE
ROTARY HOOK
ROTARY TABLE
FLOOR TOOLS

Figure B-5. Hoisting and Rotating Subsystem

B.2.4 Mud Subsystem

The Mud Subsystem (Figure B-6) controls the escape of fluids due to pressure of formulations encountered during drilling, cools and cleans the drill bit, flushes the cuttings from the hole, and cakes the walls of the hole to prevent sloughing and fluid loss. In performing these functions, the subsystem equipment provides circulating pressure, establishes

a portion of the circulating flow path that interfaces with the drill string and casing head, and conditions the mud. Mud monitoring equipment is also vital to intelligent interpretation and control of downhole activity and conditions. Mud control is required to properly handle hazards such as potential blowouts, lost circulation, heaving shale problems, and salt section hole enlargement. The mud pump must circulate the mud at the desired volume and pressure; the mud should not require excessive pump pressure at the desired circulation rate.

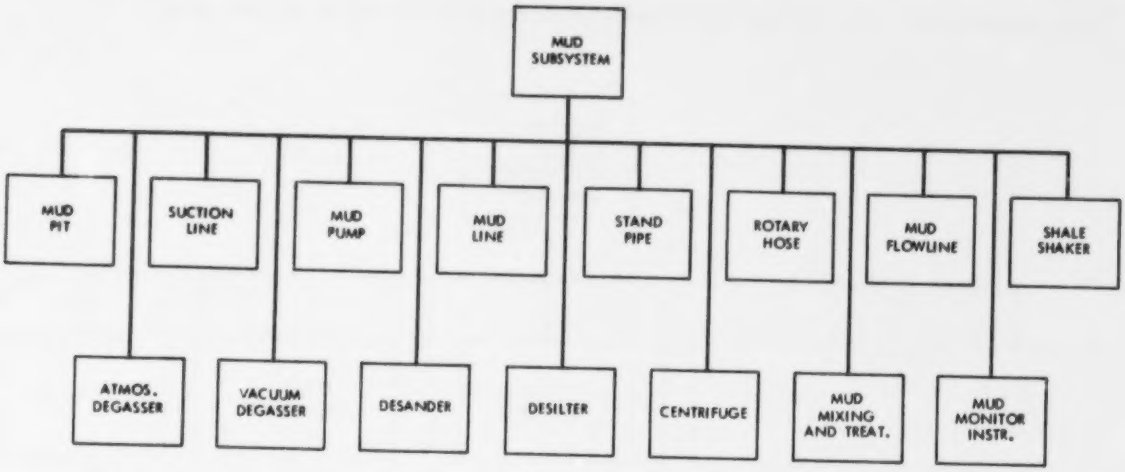
MUD SUBSYSTEM
MUD PIT
SUCTION LINE
MUD PUMP
MUD LINE
STAND PIPE
ROTARY HOSE
MUD FLOWLINE
SHALE SHAKER
ATMOS. DEGASSER
VACUUM DEGASSER
DESANDER
DESILTER
CENTRIFUGE
MUD MIXING AND TREAT.
MUD MONITOR INSTR.

Figure B-6. Mud Subsystem

B.2.5 Drill String Subsystem

The Drill String Subsystem (Figure B-7) includes the joined sections of drill pipe, the drill bit, drill collars, kelly and kelly cock, swivel, and may also include special tools to perform special functions. These are the tools required to drill to the necessary depth while providing a circulating path for mud flow.

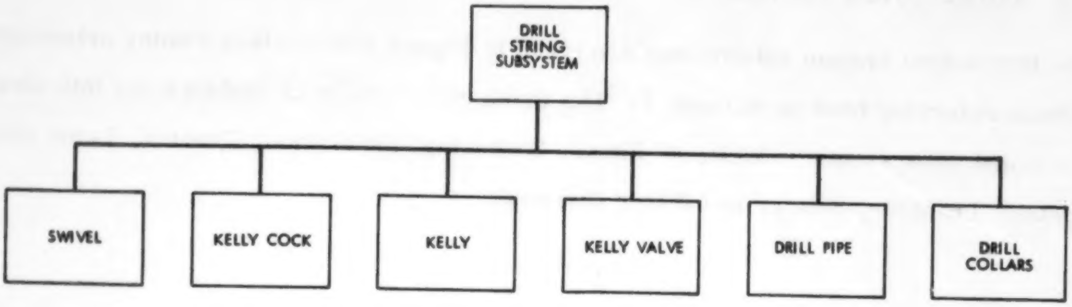
DRILL STRING SUBSYSTEM
SWIVEL
KELLY COCK
KELLY
KELLY VALVE
DRILL PIPE
DRILL COLLARS

Figure B-7. Drill String Subsystem

B.2.6 Blowout Preventer (BOP) Subsystem

The Blowout Preventer (BOP) Subsystem (Figure B-8) closes off the annular space between the drill pipe and casing if the mud column in the hole becomes underbalanced with formation pressures and flow occurs during drilling operations. This situation is called a "kick." Several available types of BOPs are pipe ram, blind ram, annular, or downhole (new development). BOP equipment also controls pressures encountered until kicks are cured by adjusting the weight of the mud column to the desired overbalanced condition. Special kill equipment and procedures, in conjunction with the Mud Subsystem, can provide the means to maintain this control and to prevent blowouts.

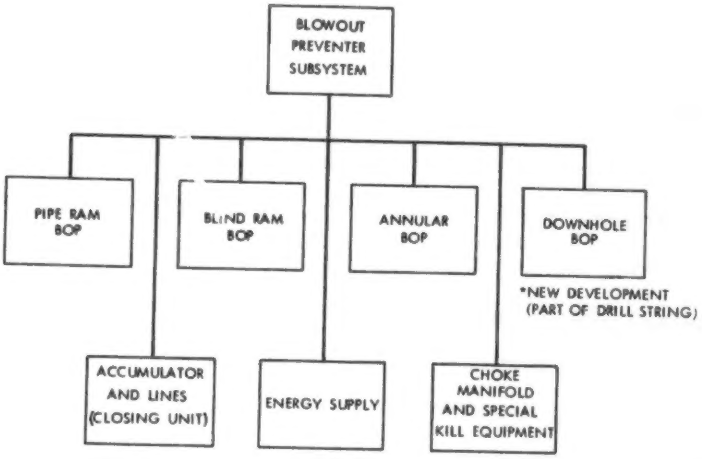
BLOWOUT PREVENTER SUBSYSTEM
PIPE RAM BOP
BLIND RAM BOP
ANNULAR BOP
DOWNHOLE BOP
*NEW DEVELOPMENT (PART OF DRILL STRING)
ACCUMULATOR AND LINES (CLOSING UNIT)
ENERGY SUPPLY
CHOKE MANIFOLD AND SPECIAL KILL EQUIPMENT

Figure B-8. Blowout Prevention Subsystem

B.3 PRODUCTION SYSTEM

The Production System subsystems are given in Figure B-9 to allow reader orientation without referring back to Volume I. The Production System is broken down into nine functional subsystems -- Well, Wellhead, Gathering, Separation, Treater, Local Storage, Custody Transfer, Safety, and Water Disposal.

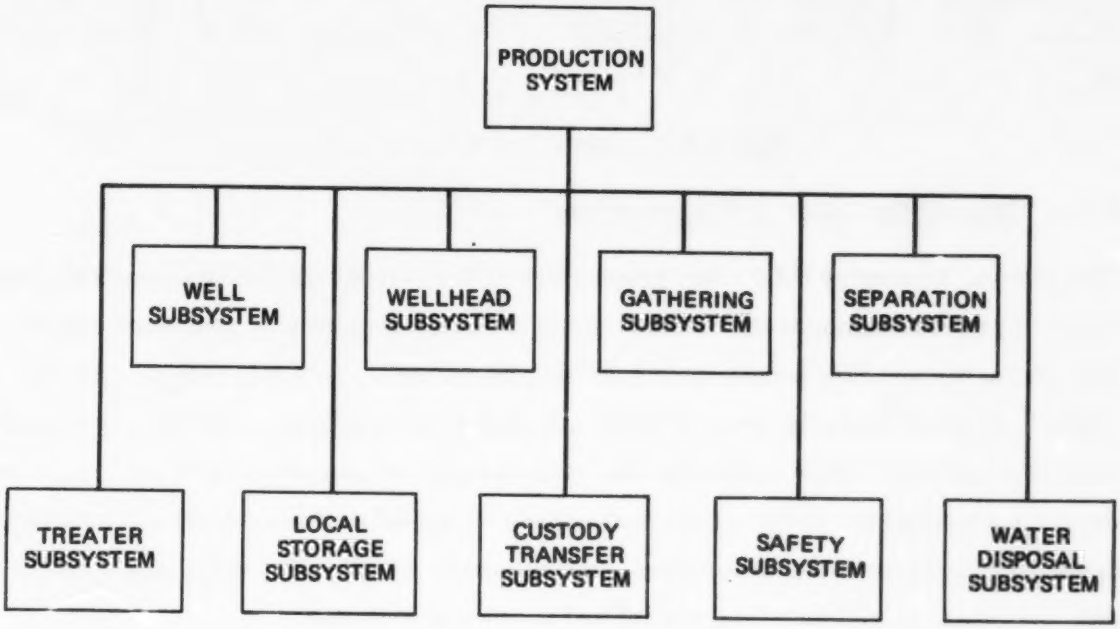
PRODUCTION SYSTEM
WELL SUBSYSTEM
WELLHEAD SUBSYSTEM
GATHERING SUBSYSTEM
SEPARATION SUBSYSTEM
TREATER SUBSYSTEM
LOCAL STORAGE SUBSYSTEM
CUSTODY TRANSFER SUBSYSTEM
SAFETY SUBSYSTEM
WATER DISPOSAL SUBSYSTEM

Figure B-9. Production System

B.3.1 Well Subsystem

The Well Subsystem (Figure B-10) is a continuous path through which the liquids and gas flow from the producing formation to ground level. The components required to perform this task are producing zone, surface casing, intermediate casing (if required), oil string casing, production tubing, packer, casing shoe, cement, liner hangers, and liners. The basic Well Subsystem varies from well to well as production characteristics require. The functions of the casing in a completed and producing well are to furnish a permanent borehole of a known diameter through which production operation may be conducted, to segregate formations behind pipe which permits production from specific zones and prevents interformational flow, and to provide a means of attaching surface valves and connections. The cement provides additional support for casings and prevents formation pressures from being imposed on the pipe. The cement also retards pipe corrosion by minimizing contact between pipe and water formations.

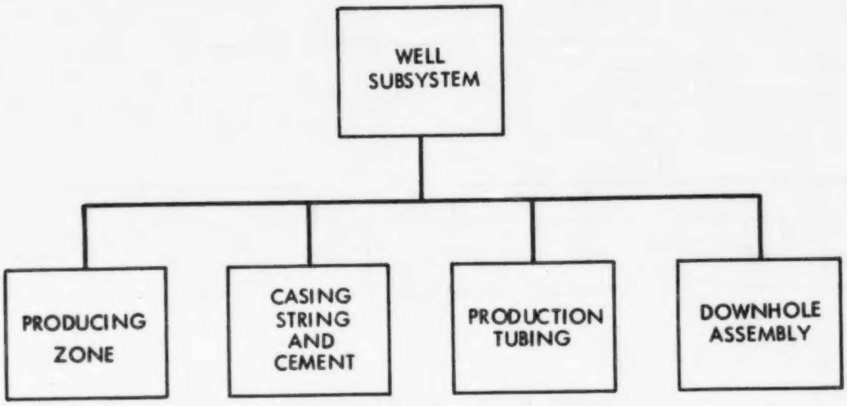

Figure B-10. Well Subsystem

B. 3. 2 Wellhead Subsystem

The Wellhead Subsystem (Figure B-11) provides surface flow control of fluids produced by the Well Subsystem and supports the weight of downhole equipment. As in the instance of the well, the wellhead configuration is determined by the well characteristics. Basically, the wellhead equipment consists of casing head(s), tubing head, and surface controls Christmas tree). Wellhead Subsystems vary widely to accommodate forms of artificial lift and flowing wells. Some of the variations encountered during the field surveys were: Single Completion Flowing, Multiple Completion Flowing, Gas-Life, Rod Pump, Hydraulic-Life, and Electric Downhole Pump.

B. 3. 3 Gathering Subsystem

The Gathering Subsystem (Figure B-12) includes flowlines, manifolds, headers, fixed and adjustable chokes, metering, and automatic control equipment. It transports the crude oil from the various wells through the manifold at the gathering point, where the output of the wells is directed to the separation and/or treatment processes to prepare the oil for sale. Provision is usually made for isolating individual wells for periodic well tests. The manifold consists of valve, headers, scraper (pig) traps, and sometimes chokes, meters, and automatic control equipment.

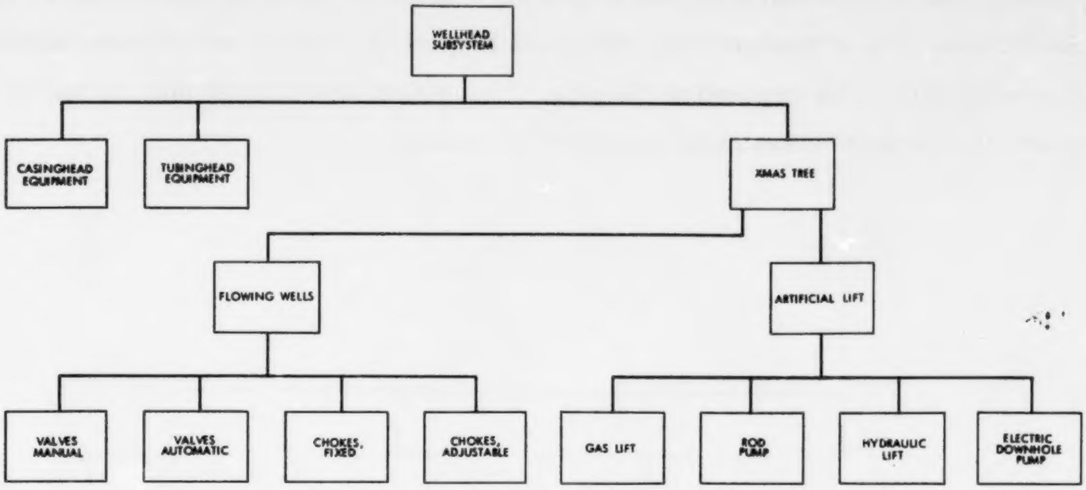
WELLHEAD SUBSYSTEM
CASINGHEAD EQUIPMENT
TUBINGHEAD EQUIPMENT
XMAS TREE
FLOWING WELLS
ARTIFICIAL LIFT
VALVES MANUAL
VALVES AUTOMATIC
CHOKES, FIXED
CHOKES, ADJUSTABLE
GAS LIFT
ROD PUMP
HYDRAULIC LIFT
ELECTRIC DOWNHOLE PUMP

Figure B-11. Wellhead Subsystem

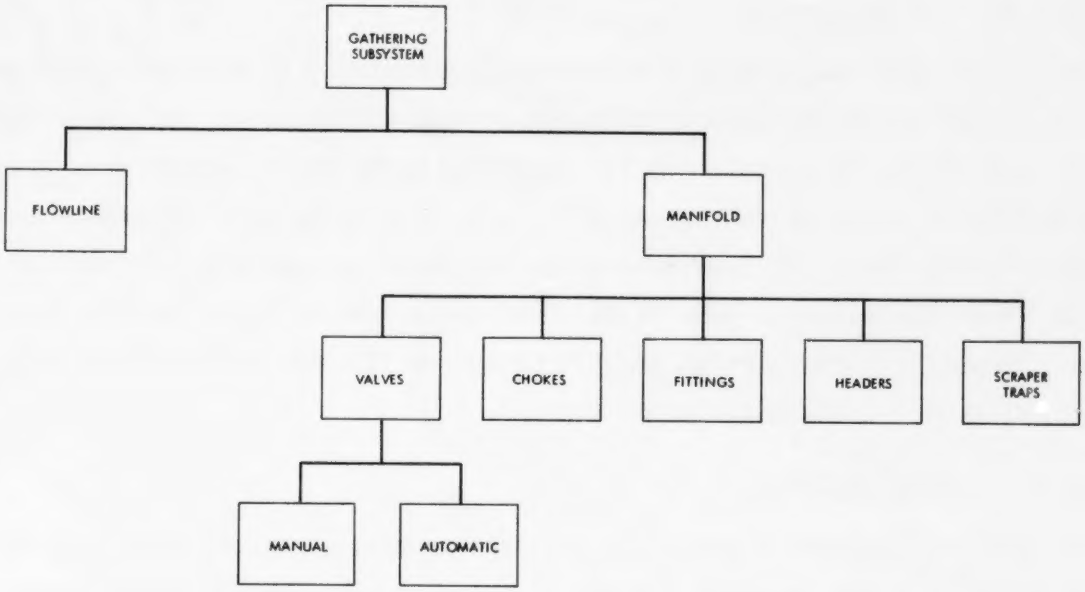
GATHERING SUBSYSTEM
FLOWLINE
MANIFOLD
VALVES
CHOKES
FITTINGS
HEADERS
SCRAPER TRAPS
MANUAL
AUTOMATIC

Figure B-12. Gathering Subsystem

B. 3. 4 Separation Subsystem

The Separation Subsystem (Figure B-13) uses mechanical methods of separation, based upon Stoke's law, to separate gas from produced liquids (oil, water, and emulsion). Occasionally a three-phase separator is used to further separate the oil and emulsion from the water. The basic equipment is gas-liquid separators and scrubbers. The gas-liquid, gas-crude oil, or gas-crude oil-water separators fall into three categories: high, intermediate, and low pressure. Scrubbers trap entrained liquids from the gas prior to gas sale or other disposal. Throughput flow is controlled by automatic dump valves and backpressure regulators, all of which are preset to automatically accommodate continuous operations, normal variations, and surges.

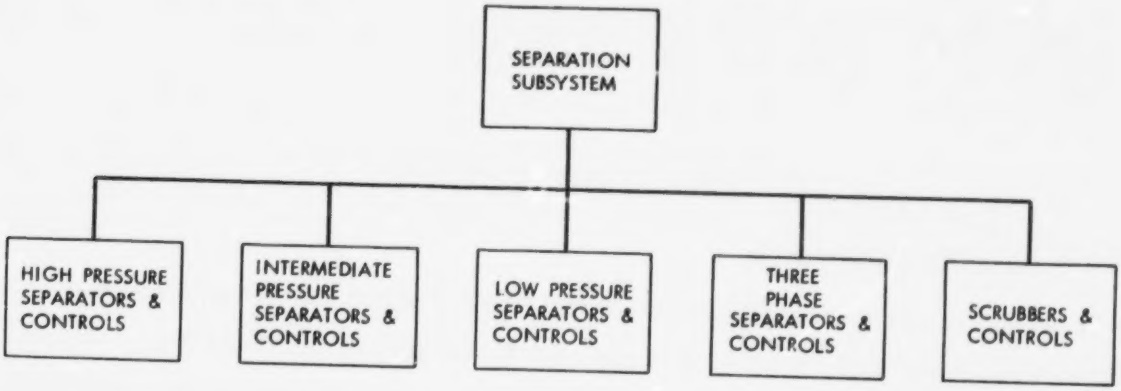
SEPARATION SUBSYSTEM
HIGH PRESSURE SEPARATORS & CONTROLS
INTERMEDIATE PRESSURE SEPARATORS & CONTROLS
LOW PRESSURE SEPARATORS & CONTROLS
THREE PHASE SEPARATORS & CONTROLS
SCRUBBERS & CONTROLS

Figure B-13. Separation Subsystem

B. 3. 5 Treater Subsystem

The Treater Subsystem (Figure B-14) contains heater-treaters, chemical treaters, chem-electric treaters, gun barrels, settling tanks, free water knockouts, skimming tanks, and precipitators to further separate water/sediment which is emulsified within the crude oil or to separate oil emulsified in water. Chemical injection to aid in demulsification is also included under this subsystem. A vessel called a desander, designed to separate sand from produced fluid, is included in the Treater Subsystem. The Treater Subsystem throughput, like that of the Separation Subsystem, is controlled by automatically operated dump valves and backpressure regulators.

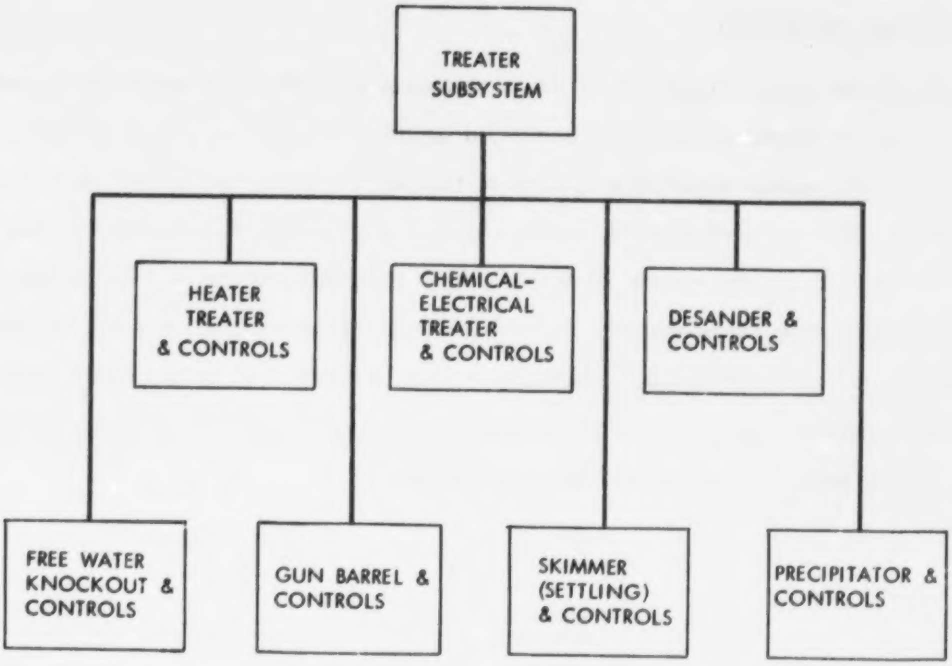
TREATER SUBSYSTEM
HEATER TREATER & CONTROLS
CHEMICAL-ELECTRICAL TREATER & CONTROLS
DESANDER & CONTROLS
FREE WATER KNOCKOUT & CONTROLS
GUN BARREL & CONTROLS
SKIMMER (SETTLING) & CONTROLS
PRECIPITATOR & CONTROLS

Figure B-14. Treater Subsystem

B.3.6 Local Storage Subsystem

The Local Storage Subsystem (Figure B-15) includes storage tanks, sump tanks, and equipment such as pumps, valves, level indicators, and fire walls. The "flow," "lease," or "stock" tanks considered in the report are, primarily, or bolted or welded construction. These tanks store the crude oil until it is sold to the pipeline. Either manual or automatic monitoring and control of liquid levels provides for continuous receipt of oil into one tank until it is full, and then switches the flow to another tank. High and low liquid measurements can be used to calculate oil sales by the manual mode mentioned under the Custody Transfer Subsystem.

B.3.7 Custody Transfer Subsystem

The Custody Transfer Subsystem (Figure B-16) gauges, switches, and measures the sales grade crude oil to a customer, i.e., pipeline, barge, tanker. Typical configurations of this subsystem are manual, lease automatic custody transfer (LACT). The subsystem consists of pumps and their controls, manifolds, prover tanks, BS&W monitor equipment, metering, and sampling equipment.

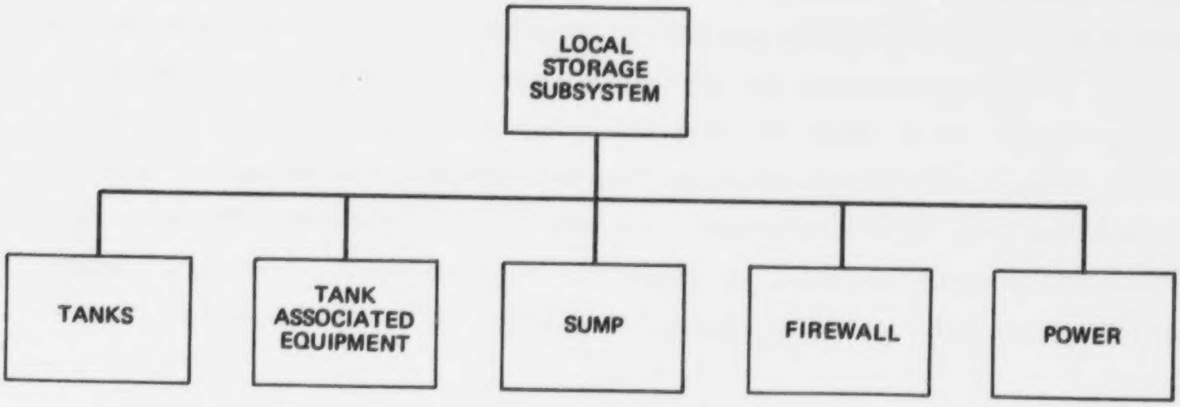
LOCAL STORAGE SUBSYSTEM
TANKS
TANK ASSOCIATED EQUIPMENT
SUMP
FIREWALL
POWER

Figure B-15. Local Storage Subsystem

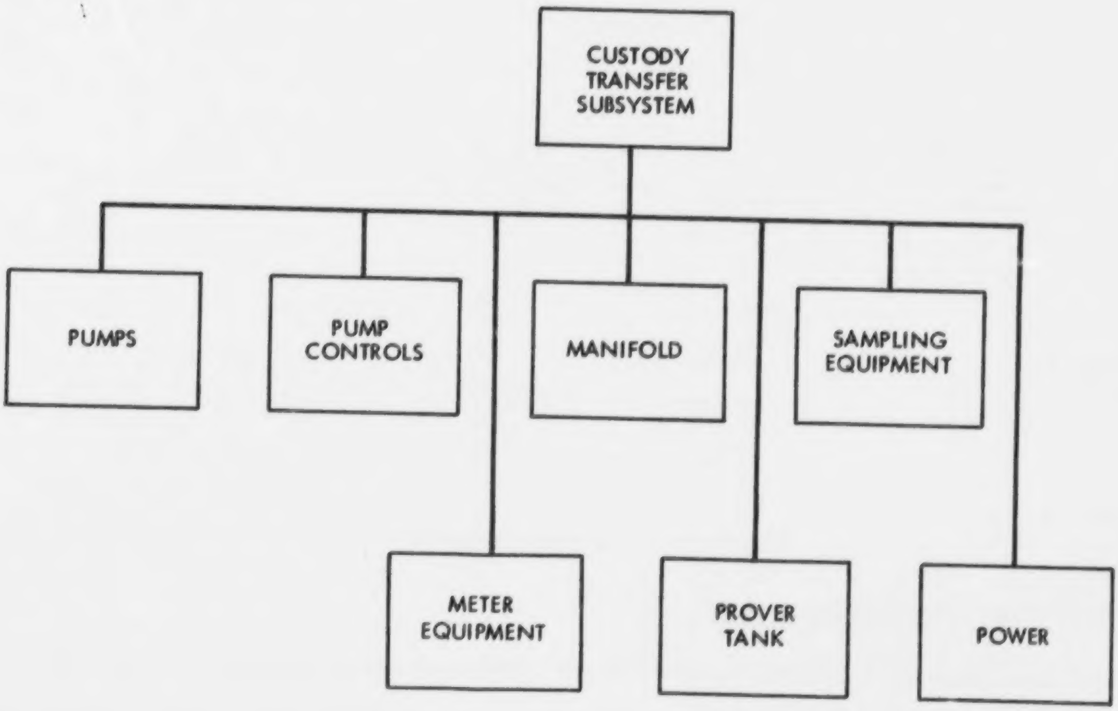
CUSTODY TRANSFER SUBSYSTEM
PUMPS
PUMP CONTROLS
MANIFOLD
SAMPLING EQUIPMENT
METER EQUIPMENT
PROVER TANK
POWER

Figure B-16. Custody Transfer Subsystem

B.3.8 Safety Subsystem

The Safety Subsystem (Figure B-17) protects facilities, equipment, personnel, and wells by providing selective or overall shutdown and/or alarm if a fire occurs or if pressures, temperatures, liquid levels, or gas concentrations have exceeded previously determined limits. The subsystem equipment may include remote (surface) controlled subsurface safety valves, velocity controlled subsurface safety valves (storm chokes), surface safety valves, monitoring and actuating pilots and sensors, fusible plugs, fusible control distribution lines, liquid level sensors, pressure sensors, gas sniffers and detectors, safety system energy source(s), and monitoring and alarm panels. Appendix J provides additional information on safety shutdown devices from USGS data from Gulf OCS inspections.

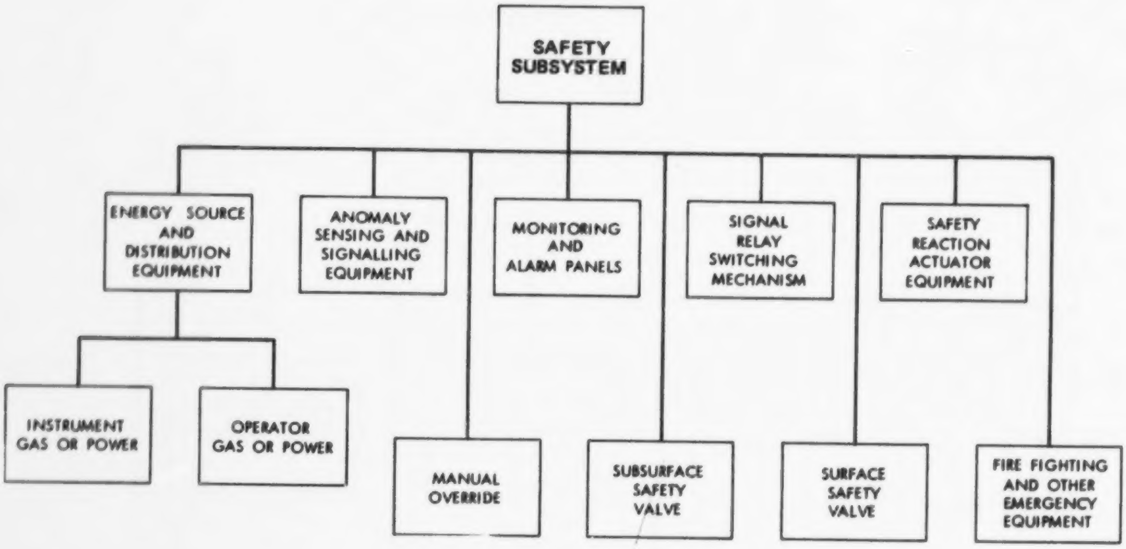
SAFETY SUBSYSTEM
ENERGY SOURCE AND DISTRIBUTION EQUIPMENT
ANOMALY SENSING AND SIGNALLING EQUIPMENT
MONITORING AND ALARM PANELS
SIGNAL RELAY SWITCHING MECHANISM
SAFETY REACTION ACTUATOR EQUIPMENT
INSTRUMENT GAS OR POWER
OPERATOR GAS OR POWER
MANUAL OVERRIDE
SUBSURFACE SAFETY VALVE
SURFACE SAFETY VALVE
FIRE FIGHTING AND OTHER EMERGENCY EQUIPMENT

Figure B-17. Safety Subsystem

B.3.9 Water Disposal Subsystem

The Water Disposal Subsystem (Figure B-18) consists of water conditioning schemes used to process the water to meet various requirements prior to disposal. These conditioning processes include disposal of produced salt water or injection of water into oil producing formations to enhance recovery of the oil. The equipment in this subsystem complements the equipment that processes water in various other subsystems, such as the Treater Subsystem. Some of the equipment comprises filters, clarifying tanks, flotation cells (both diffused gas or floculant types), oxygen stripping tanks, various pumps and turbines, settling pits or tanks, and injection wells and associated equipment.

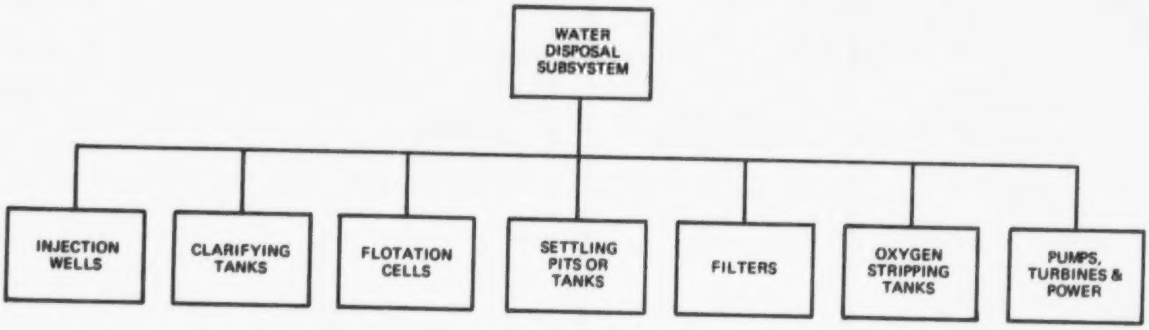
WATER DISPOSAL SUBSYSTEM
INJECTION WELLS
CLARIFYING TANKS
FLOTATION CELLS
SETTLING PITS OR TANKS
FILTERS
OXYGEN STRIPPING TANKS
PUMPS, TURBINES & POWER

Figure B-18. Water Disposal Subsystem

B.4 GATHERING/DISTRIBUTION SYSTEM

The Gathering/Distribution System subsystems are given in Figure B-19 to allow reader orientation without referring back to Volume I. The Gathering/Distribution System is broken down to five subsystems -- Pipeline, Storage, Pump Station, Safety, and Gathering.

B.4.1 Pipeline Subsystem

The Pipeline Subsystem (Figure B-20) is the pipeline network through which crude oil is transported from a control gathering point to a terminal area. The Pipeline Subsystem consists of pipe, scraper trap equipment, pipe supporting structures, stream crossing equipment, and road crossing equipment. The latter two are underwater or underground to provide safe crossing of waterways, land rights-of-way (including highways and railroads), and populated areas. Overhead crossings (or bridge crossings) are not considered since the data were insufficient to support analysis.

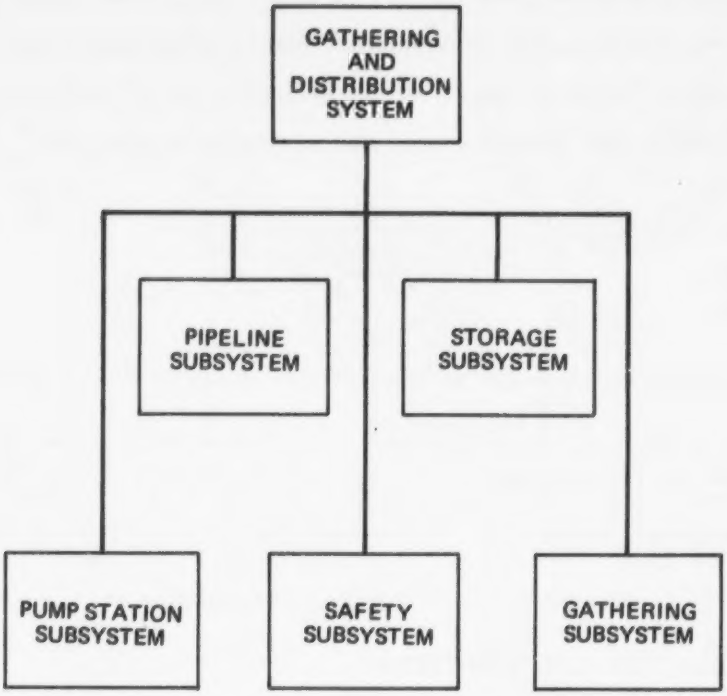
GATHERING AND DISTRIBUTION SYSTEM
PIPELINE SUBSYSTEM
STORAGE SUBSYSTEM
PUMP STATION SUBSYSTEM
SAFETY SUBSYSTEM
GATHERING SUBSYSTEM

Figure B-19. Gathering/Distribution System

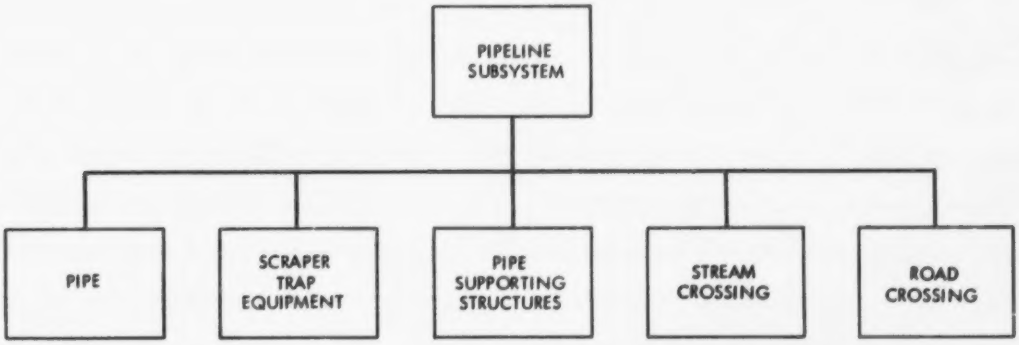
PIPELINE SUBSYSTEM
PIPE
SCRAPER TRAP EQUIPMENT
PIPE SUPPORTING STRUCTURES
STREAM CROSSING
ROAD CROSSING

Figure B-20. Pipeline Subsystem

B.4.2 Storage Subsystem

The Storage Subsystem (Figure B-21) provides short-term storage for receiving, sorting, measuring, and rerouting. The subsystem includes tanks, tank firewalls, tank-associated equipment, and power. The spacing of tanks is determined by the safe containment of oil in the event of a catastrophe. The firewall is designed to contain more than the contents of the tanks it surrounds.

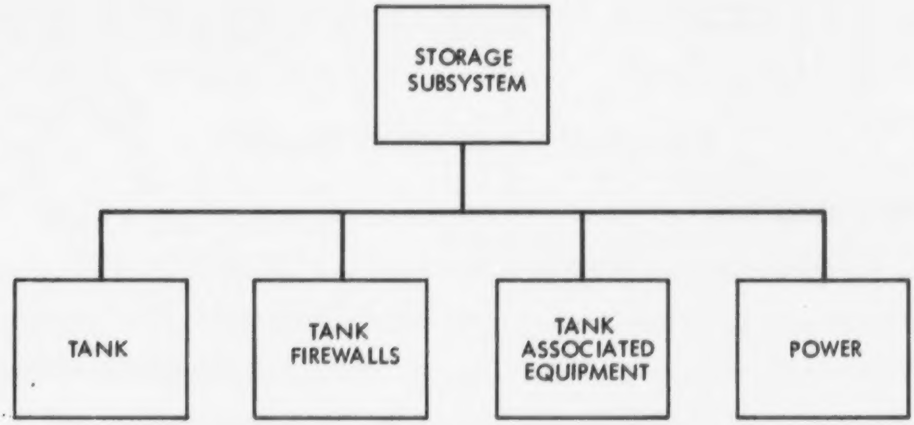

Figure B-21. Storage Subsystem

B.4.3 Pump Station Subsystem

The principal function of the Pump Station Subsystem (Figure B-22) is to provide the energy to overcome transmission energy losses and to transport the oil through the Gathering/Distribution System to its destination. Pumps, driven by their associated prime movers, overcome these losses. Flow control and switching in the subsystem are done by manifold equipment. Batch control at the Pump Station is done by metering equipment and communications equipment used to coordinate with the pipeline dispatcher.

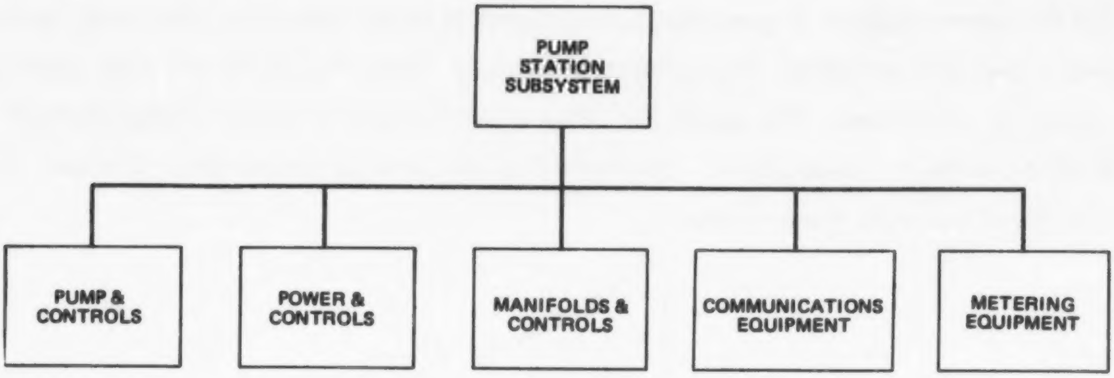
PUMP STATION SUBSYSTEM
PUMP & CONTROLS
POWER & CONTROLS
MANIFOLDS & CONTROLS
COMMUNICATIONS EQUIPMENT
METERING EQUIPMENT

Figure B-22. Pump Station Subsystem

B.4.4 Safety Subsystem

The Safety Subsystem (Figure B-23) provides for alarm or shutdown of operations through instruments indicating pipeline breaks, leaks, pump vapor locks, fire, explosive mixtures, or other undesirable conditions. Monitoring and control instrumentation of other subsystems are used to maintain desirable suction and discharge pressures and to detect leaks, breaks, or other pump station failures. High-level alarms on sumps and low air-pressure alarms on controllers of automated valves are examples of other safety devices in use. Appendix J provides additional information on safety shutdown devices from Gulf OCS inspections.

B.4.5 Gathering Subsystem

The Gathering Subsystem performs a switching and gathering function using components essentially the same as those in the Pipeline Subsystem (see Figure B-20).

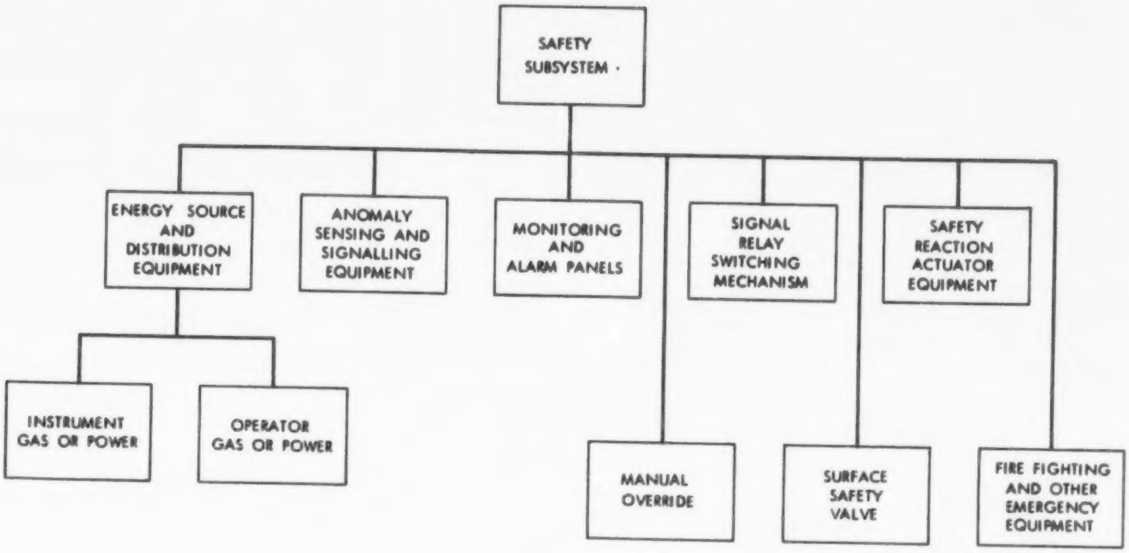
SAFETY SUBSYSTEM
ENERGY SOURCE AND DISTRIBUTION EQUIPMENT
ANOMALY SENSING AND SIGNALLING EQUIPMENT
MONITORING AND ALARM PANELS
SIGNAL RELAY SWITCHING MECHANISM
SAFETY REACTION ACTUATOR EQUIPMENT
INSTRUMENT GAS OR POWER
OPERATOR GAS OR POWER
MANUAL OVERRIDE
SURFACE SAFETY VALVE
FIRE FIGHTING AND OTHER EMERGENCY EQUIPMENT

Figure B-23. Safety Subsystem

APPENDIX C

SOURCE DATA BANK DESCRIPTIONS

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APPENDIX C

SOURCE DATA BANK DESCRIPTION

C.1 INTRODUCTORY SUMMARY

The spill prevention program described in this report has wide application to United States petroleum systems as a result of the broad data base from the several sources described in this appendix. Data requirements, in terms of specific data elements, were established early in the study and are documented in Appendix K. A search was conducted to locate sources of oil spill data from Federal activities and agencies of major oil-producing States. Data were collected by having study team engineers contact the source agencies, review the data at the agency's facilities and identify the spill records of interest to this study. To properly use the data, information describing each source was required. This appendix is included to evaluate the data in Appendix D in terms of the specific data sources. The format shown in Figure C-1 was developed as a guide to the type of information desired for each data bank.

C.2 DESCRIPTION OF SOURCE DATA BANKS

The data banks that were contacted as sources for oil spill events are listed in Figure C-2. The remainder of this appendix presents descriptions of each bank, to the extent that information was available, according to the format of Figure C-1.

1. Data Bank Name: Indicate the name of the data bank.

2. Data Bank Location: Indicate the name and address of the agency that has custody of the Data Bank.

3. Data Bank Structure: Indicate the way the data is presented, such as use of forms, summary reports, computerization, etc.

4. Scope: Describe the coverage and depth of the data. Indicate what is and is not covered by the data source in regard to cause and prevention of oil spillage. Identify reporting relationships with other data banks: Is this a central data bank? Are there other banks that supply this bank? Is this a local or regional bank? Are there other banks that receive data from this bank? Identify name and location for related banks.

5. Reporting Requirements: Describe the requirements for reporting a spill. Indicate when the report is to be filed, who is required to report, to whom, where, and the regulation that sets down the requirement. Include copies of any reporting forms and instructions.

6. Purpose: Describe, to the extent possible, the agency's purpose for having the data bank and what the agency does with the bank. Is the actual use of the same as the stated purpose? If purpose of the data bank is not clear, so state.

7. Items Contained in Data Bank: Describe any data elements that may need clarification or interpretation. Include any data element description or definitions.

8. Time Span Covered by Study Data: Indicate the start and end dates of the data used in the study.

9. Volume of Data: Indicate the number of reports on crude oil spills. Record the number of reports on spills of other products also.

10. Limitations and General Comments on Data Bank: Present any comments on the data and specify any deficiencies of the data bank with regard to this study.

Figure C-1. Format for Development of Source Data Bank Descriptions

Federal

1. Environmental Protection Agency Headquarters – Oil and Hazardous Material File
2. EPA Anchorage, Alaska
3. Department of Transportation/Federal Railroad Commission – Pipeline Carrier Accident Reports
4. U. S. Coast Guard
5. U.S. Geological Survey, Conservation Division, Washington, D.C. Office

States

★ 1. Alaska – Department of Natural Resources, Division of Oil and Gas
★ 2. Arkansas Oil and Gas Commission
3. California – Department of Fish and Game Commission
4. California – Water Quality Control Board
5. California – Division of Oil and Gas
6. California – City of Long Beach, Department of Oil Properties
7. Colorado – Department of Health, Water Pollution Control Division
8. Louisiana – Department of Conservation, Division of Minerals (2 files: New Orleans and Baton Rouge)
9. Mississippi – Oil and Gas Board
10. New Mexico – Oil Conservation Commission
11. Oklahoma – Corporation Commission, Oil and Gas Conservation Division
12. Texas – Railroad Commission, Oil and Gas Division

Other

★ 1. Western Oil and Gas Association, California
2. Alberta, Canada – Alberta Oil and Gas Conservation Board
★ 3. Alberta, Canada – Department of Mines and Minerals, Superintendent of Pipelines

★ Data from these sources were not pertinent to this study.

Figure C-2. List of Oil Spill Data Sources Contacted

EPA HEADQUARTERS-OHM FILE

1. Data Bank Name: Environmental Protection Agency
Oil and Hazardous Material (OHM) File

2. Data Bank Location: Environmental Protection Agency
Office of Water Programs
Arlington, Virginia

3. Data Bank Structure: Narrative data are transcribed from situation reports onto data forms for subsequent entry into a time-shared computer system file. Twenty-eight data items are included, the majority of which are of unknown length.

4. Scope: The file provides a record of oil and hazardous material spills reported to EPA via a number of government agencies.

5. Reporting Requirements: Extracted normally from situation reports by USCG and USGS, related to spills of interest. EPA does not generally get direct reports, although representatives may provide on-site monitoring.

6. Purpose: The file serves the EPA staff as a ready in-house source of up-to-date information on OHM spill events of interest. It may also provide data to support recommended regulations.

7. Items Contained in Data Bank: The data file record permits the storage of at least the following data items that were of use to this study:

    - Title - a short title given to the spill event, followed by the spill location: State, County, City.
    - Date spill occurred - self explanatory: month, day, and year.
    - Duration of spill - self explanatory: in days, hours, and minutes.
    - Type of water area - one of 11 specific descriptors.
    - Quantity spilled - the quantity of oil spilled: in barrels, gallons, or pounds.
    - Source of spill - identity of the exact or suspected source of pollution or threat of pollution.
    - Organization causing spill - the name and address of the responsible party or suspected responsible party.
    - Specific cause - description of activity surrounding the cause.
    - Type of operation - self-explanatory.

8. Time Span Covered by Study Data: June 1969 to June 1971.

9. Volume of Data: 113 reports of crude oil spill events. 108 reports were used in this study.

10. Limitations and General Comments on Data Bank: A manual review of all data recording forms for the file indicates three deficient areas that limit its utility in some applications. These are:

    a. The data items are stored in narrative format with little recording standardization.
    b. Many of the identified data items contain no information.
    c. The file does not provide specific information on the hardware-related causes of spills.

EPA ANCHORAGE ALASKA

1. Data Bank Name: Environmental Protection Agency
Anchorage Office File

2. Data Bank Location: Environmental Protection Agency
Federal Building (Post Office Building)
602 4th Street
Anchorage, Alaska

3. Data Bank Structure: The data bank consists of handwritten notes of observations, telephone messages, USCG Form CG 3639 Water Pollution, Federal Water Quality Administration (Alaska Operations Office) Oil Pollution Report, memoranda, FAA reports, and TWXs. Reports are chronologically filed.

4. Scope: It was indicated that this oil spillage file was the most complete in the Alaskan area, including State and Coast Guard files. The following data is usually attained, even though in widely variable format:

- Date and Time Received
- Date and Time of Occurrence
- Location
- Source of Information
  - Description
  - Action Taken

5. Reporting Requirements: No formal requirements are apparent. However, reports usually contain the items listed in item 4, Scope.

6. Purpose: To keep track of oil pollution in waters and to identify offenders for appropriate action. Also monitors events and evaluates clean ups.

7. Items Contained in the Data Bank: Any pollution affecting water quality or game and wildlife. Very informal reporting, therefore, it cannot be presented in a formalized approach.

8. Time Span Covered by Study Data: The data cover the period from 1966 through the first week of August 1971.

9. Volume of Data: There were 70 reported crude oil spills contained in the data bank. The number of reports on spills of other products is unknown. 68 reports were used in this study.

10. Limitations and General Comments on Data Bank: The data is limited for purposes of reliability analysis. The data is oriented toward environmental effects, containment, and clean up of spills.

DOT/FRRC

1. Data Bank Name: Department of Transportation (DOT)
   Federal Railroad Administration
   Pipeline Carrier Accident Reports, DOT Form 7000-1

2. Data Bank Location: Federal Railroad Administration
   Department of Transportation
   400 6th Street, S.W.
   Washington, D. C.

3. Data Bank Structure: Report forms are filed as they are received. They are grouped by company with each file folder containing spills by a company. These reports are not computerized.

4. Scope: An accident report (DOT 7000-1) is required to be submitted within 15 days of any failure in a pipeline system resulting in any of the following:

   a. Explosion or fire not intentionally set by carrier.

   b. Loss of 50 or more barrels of liquid.

   c. Escape to the atmosphere of more than five barrels a day of liquefied petroleum gas or other liquefied gas.

   d. Death of any person.

   e. Bodily harm to any person.

   f. Property damage of at least $1000 to other than the carrier's facilities.

5. Reporting Requirements: The report is to be filed with the Administrator, Federal Railroad Administration, Department of Transportation, Washington, D.C. by the responsible carrier company.

6. Purpose: Any company coming under ICC regulations is required to submit Form 7000-1. The reports are intended to form a basis for judging the effectiveness of existing regulations and for indicating need for action in protecting public interests.

7. Items Contained in Data Bank:

   a. Part I - Accidents caused by corrosion.

   b. Part J - Accidents caused by equipment rupturing the pipeline.

   c. The carrier is to provide an account of the accident.

8. Time Span Covered by Study Data: Beginning of 1968 to August 1971.

9. Volume of Data: There were 860 reports on file at DOT containing data on crude oil spills. 802 reports were used in this study.

10. Limitations and General Comments on Data Bank: The major deficiencies of Form 7000-1 are as follows:

    a. There is no consistency of information contained in the narrative portion of the form.

    b. No accurate assessment can be made of the volume of oil spilled.

    c. The repairs made and the parts replaced are not often given.

    d. The length of time of the leak is not often given.

    e. It is usually impossible to distinguish between production and transportation pipelines.

    f. It is usually impossible to distinguish between gathering and trunk pipelines.

U.S. COAST GUARD

1. Data Bank Name: Department of Transportation
   U.S. Coast Guard
   Law Enforcement Branch File

2. Data Bank Location: Department of Transportation
   U.S. Coast Guard
   Washington, D.C.

3. Data Bank Structure: Water pollution incidents are classified as major or minor. Major events are covered by U.S. Coast Guard Form CG 3639 (Rev. 7-68). Minor events are reported as single line entries, usually by TWX. Data in 1970 and subsequent have been coded and computerized but no narrative has been included. A series of computer summaries is available.

4. Scope: Data prior to 1970 is very limited. The data bank covers all types of water pollution within coastal and navigable waters (including inland waters, the Great Lakes, the high seas, and the continuous zone).

5. Reporting Requirements: Any pollution incident threatening navigable water is reported.

6. Purpose: The data bank supports the law enforcement responsibilities of the Coast Guard and provides a basis for pollution control or prevention in water under cognizance of the U.S. Coast Guard.

7. Items Contained in Data Bank: Only those incidents that resulted in a water pollution problem.

8. Time Span Covered by Study Data: January 1970 through June 1971.

9. Volume of Data: 3743 major pollution incidents were recorded in 1970. No reports were used in this study.

10. Limitations and General Comments on Data Bank:

    a. Less than 1 percent of the recorded incidents pertained to crude oil spills from Drilling, Production, and Gathering/Distribution Systems.

    b. Inland incidents, which did not threaten navigable water were not usually recorded in this data bank.

U.S. GEOLOGICAL SURVEY

1. Data Bank Name: Department of the Interior
   Geological Survey
   Monthly Pollution Report

2. Data Bank Location: Department of the Interior
   Geological Survey
   Conservation Division
   General Services Administration Building
   Room 3243
   Washington, D.C.

3. Data Bank Structure: The USGS Office in Washington receives a Monthly Pollution Report from Regional Offices in New Orleans and Los Angeles. These reports give brief descriptions of all reported oil spills in each OCS region in short narrative form. About 12 incidents are recorded, sequentially by date of occurrence, on each page.

4. Scope: For each reported offshore oil spill the information includes date of spill, place, amount, cause, and repair action taken. The USGS exercises control over about 40,000 oil wells on Federal and Indian lands. The main offshore drilling and production of petroleum is in the Gulf Coast region. About 8000 wells are included in U.S. offshore operations. There are no reports on spills in land operations.

5. Reporting Requirements: The USGS has initiated a monitoring program of all offshore drilling and production wells. As of July 1971, a fleet of six helicopters continually observe drilling and production activities.

6. Purpose: The USGS supervises operations incident to the prospecting, development, and production of minerals on Federal, Indian, and Naval Petroleum Reserve Lands under Federal lease, license, and prospecting permits.

7. Items Contained in Data Bank: A file of the Monthly Pollution Reports is maintained.

8. Time Span Covered by Study Data: The Monthly Pollution Report was initiated in June 1970. The data coverage extends from June 1970 through October 1971.

9. Volume of Data: 643 oil spill events. 633 reports were used in this study.

10. Limitations and General Comments on Data Bank:

    a. The Monthly Pollution Report contains quite brief summaries entered by dates of occurring events, but the data content does not support reliability analysis.

    b. In the onshore area of USGS responsibility there is no documentation of pipeline spills and none on drilling or production except for major blowouts.

ALASKA DEPARTMENT OF NATURAL RESOURCES

1. Data Bank Name: Alaska Department of Natural Resources
Division of Oil and Gas File

2. Data Bank Location: Division of Oil and Gas
3001 Porcupine Drive
Anchorage, Alaska 99504

3. Data Bank Structure: Undefined.

4. Scope: It was indicated that any crude oil spillage event would be in the EPA Anchorage, Alaska file.

Information on Items 5 through 10 was not determined.

ARKANSAS OIL AND GAS COMMISSION

1. Data Bank Name: No spill data file exists.

2. Data Bank Location: None.

3. Data Bank Structure: A letter report to the Commission is required for oil losses that exceed 25 barrels.

4. Scope: Rule B-34 of the General Rules and Regulations Relating to Oil and Gas of the State of Arkansas requires that the Commission be notified immediately by letter of fire, breaks, leaks, or blowouts. The letter should cover any destruction of gas or oil, leaks from tanks or pipelines, overflowing of tanks, and steps taken or in progress to remedy the situation. A report is necessary only when losses exceed 25 barrels.

5. Reporting Requirements: It was indicated that spill reports are not required. However, there is a requirement that pipeline losses are reported as to quantity spilled, how much recovered, and where the balance went. No additional details are given. This information is noted and included in monthly inventory reports required by the state. The same type reports are submitted monthly by producers; these are purely inventory control and do not require spill reports.

6. Purpose: Inventory control of crude produced, stored, and transported in advance for regulatory purposes.

7. Items Contained in Data Bank: None at time of review.

8. Time Span Covered by Data Bank: None.

9. Volume of Data: None.

10. Limitations and General Comments on Data Bank: A legal requirement exists for letter reporting of certain types of oil spillage exceeding 25 barrels. However, a permanent record file has not been established.

CALIFORNIA DEPARTMENT OF FISH AND GAME COMMISSION

1. Data Bank Name: State of California
   Department of Fish and Game (F&GD)

2. Data Bank Locations: Data on pollutants, including oil, entering California water bodies are maintained in the headquarters office in Sacramento and the regional offices.

3-4. Data Bank Structure and Scope: The structures of the three data banks that were reviewed varied considerably. Each data bank is discussed separately.

   a. Headquarters - Reports, including those on the WQCB Form C-11, are submitted on all types of polluting incidents. A majority of these reports deal with pollution by manufacturing, transportation, and agricultural systems.

   b. Region 3 - A "Citation Record" card file is maintained which contains items of legal action proposed or pending against polluters. This file contains mostly complaints against shipping companies for bilge pumping and loading-unloading spillages. The information items on the cards are designed to provide documentation on the history of legal action and do not generally delve into causes.

   c. Region 5 - The only formal data was a compilation made for the year 1967. It contained information on (1) date, (2) company name, (3) operation (i.e., production, tank farm, etc.), (4) cause, (5) barrels spilled and (6) action (legal).

   Note: Data from Regions 1, 2, & 4 was nil.

5. Reporting Requirements: The Department of Fish and Game has a standardized form for use throughout the state.

6. Purpose: To support legal action by the Department of Fish and Game against those who are responsible for pollution of California waters.

7. Items Contained in Data Bank: The total data bank consists of complaints from all sources of pollution, i.e., petroleum, transportation, manufacturing, agricultural and other industries or individuals. On oil spills related to the petroleum reliability study, the most common information items are (1) spill date, (2) operator's name, (3) time, (4) location, (5) limited details and (6) data related to actions and activities of Federal, State, and local agencies.

8. Time Span Covered by Study Data: The data collected covers the period as follows:

Headquarters - January 5, 1970 to September 8, 1971

Region 3, San Francisco - May 25, 1969 to January 3, 1970

Region 5, Long Beach - January 3, 1967 to December 29, 1967

9. Volume of Data:

Headquarters - Of 1000 spills recorded, only 24 were relevant to this study.

Region 3, San Francisco - Of 200, only seven were relevant.

Region 5, Long Beach - Of 78 citations in 1967, 55 were relevant.

A total of 63 non-duplicated records were used in this study.

10. Limitations and General Comments on Data Bank: The major deficiencies are as follows:

a. Mandatory written reports on a standardized form are not required.

b. Available reports lack technical detail necessary to reliability analysis.

CALIFORNIA WATER QUALITY CONTROL BOARD

1. Data Bank Name: State of California
   Water Quality Control Board (WQCB)

2. Data Bank Locations: Oil spill data records are maintained in some regional offices, but not in the headquarters office, Sacramento.

3. Data Bank Structure: WQCB Form C-11 is used to document details of pollutants entering state waters. Use of this form does not seem to be a standard practice for all districts in the state and for all polluting incidents within any district.

   Data for three oil spills for Region 3 was provided from information in the files.

4-5. Scope and Reporting Requirements: The Porter-Cologne Water Quality Control Act of November 1970 establishes that any discharge of waste that could affect water quality in the state must be reported.

6. Purpose: To serve the intent of the Porter-Cologne Water Quality Control Act.

7. Items Contained in Data Bank: The total data bank consists of complaints from all sources of pollution, i. e., petroleum, transportation, manufacturing, agricultural and other industries or individuals. On oil spills which are related to this study, the most common information items are (1) spill data, (2) operator's name, (3) time, (4) location, (5) limited details, and (6) data related to actions and activities of Federal, State and local agencies.

8. Time Span Covered by Study Data: September 1968 through September 1971.

9. Volume of Data: Twenty-one spill events, of which one was water, one was refined petroleum products, and the balance were crude oil. 19 reports were used in this study.

10. Limitations and General Comments on Data Bank: Available reports lack technical detail necessary to reliability analysis.

CALIFORNIA DIVISION OF OIL AND GAS

1. Data Bank Name: State of California
   Division of Oil and Gas File

2. Data Bank Location: Oil spill data records are maintained in the district offices.

3. Data Bank Structure: Report forms are not required by the Division of Oil and Gas. All spills are phoned in by representatives of Federal, State, county, or city political entities, oil companies, or private citizens. On occasions, the oil companies submit a letter. Some districts maintain no records; other districts keep a clipboard file.

4-5. Scope and Reporting Requirements: In 1969, the Division of Oil and Gas was assigned responsibility for monitoring all oil spills.

When an oil spill occurs, the event is logged into the file and relayed to interested parties.

6. Purpose: To monitor oil spills.

7. Items Contained in Data Bank: Key elements are spill date and time, operator's name, product spilled, location, volume of spill, area covered by spill and cause (if known).

8. Time Span Covered by Study Data: January 1969 through September 1971.

9. Volume of Data: Forty crude oil spill reports are on file in the various districts and were used in this study.

10. Limitations and General Comments on Data Bank: Available reports lack technical detail necessary to reliability analysis.

CALIFORNIA CITY OF LONG BEACH

1. Data Bank Name: City of Long Beach, California
Department of Oil Properties File

2. Data Bank Location: Department of Oil Properties
Harbor Building
Long Beach, California

3. Data Bank Structure: Narrative record maintained on a clipboard, no format.

4-5. Scope and Reporting Requirements: The Department of Oil Properties requires all oil companies that produce hydrocarbons from city-owned properties to report oil spills.

6. Purpose: To monitor and control spills of oil and other hazardous material.

7. Items Contained in Data Bank: Information items usually obtained are (a) spill date and time, (b) operator's name, (c) location, and (d) volume of spill or area covered by oil. Occasionally the cause and material spilled is reported.

8. Time Span Covered by Study Data: April 1968 through January 1971.

9. Volume of Data: Thirty crude oil spills were recorded and used in this study.

10. Limitations and General Comments on Data Bank: Data lacks technical detail necessary to reliability analysis.

COLORADO DEPARTMENT OF HEALTH

1. **Data Bank Name:** State of Colorado
   Department of Health
   Water Pollution Control Division File

2. **Data Bank Location:** Colorado Department of Health
   Water Pollution Control Division
   4201 East 11th Avenue
   Denver, Colorado 80220

3. **Data Bank Structure:** Oil spillage incidents are reported by means of memoranda, letters, activity reports, etc., which are generated by field observers of many state and some Federal agencies.

4. **Scope:** Reporting is chiefly oriented toward fresh water pollution. State Oil and Gas Board Rules and Regulations adopted in August 1971 do not establish any data requirements for pollution control or reporting of oil spills.

5. **Reporting Requirements:** There are no definite reporting requirements prescribed.

6. **Purpose:** A spill report form seems to be an "in-house" medium for documenting any kind of a substance spill.

7. **Items Contained in Data Bank:** The data items covered vary with individual reports and pertain to any spilled substance.

8. **Time Span Covered by Study Data:** April 1968 through September 1971.

9. **Volume of Data:** 12 spill events, of which 10 were crude oil, one was refined petroleum products, and one was other hazardous material. The 10 crude oil reports were used in this study.

10. **Limitations and General Comments on Data Bank:** Available data lack technical detail necessary for reliability analysis.

LOUISIANA DEPARTMENT OF CONSERVATION (NEW ORLEANS FILE)

1. Data Bank Name: State of Louisiana
   Department of Conservation
   Division of Minerals
   New Orleans District Office File

2. Data Bank Location: 307 Louisiana State Office Building
   Civic Center
   New Orleans, Louisiana 70112

3. Data Bank Structure: The earliest data is in narrative form. Later data is on an earlier (pre-October 28, 1970) form, and current data is on a standard but limited form.

4. Scope: Data related to oil spills and slicks of known and unknown origin were collected here starting in late 1969. Later, a very simplified form evolved and all reports received in the New Orleans District office were transcribed onto this form for transmittal to headquarters in Baton Rouge, Louisiana. Ultimately, the reporting format was made uniform and a specific requirement to report any spill was made, by directive.

   Since the language in the directive relates strongly to spills or slicks on water, and since there is an abundance of maritime activity in the area of the offshore and inland bay oilfields in this district, a large number of these reports identified slicks of unknown origin in the area and heading their way. These data have been deleted, although it was counted for information. There are 390 such "John Doe" reports.

5. Reporting Requirements: See Item 7.

6. Purpose: The Department requires information concerning corrective action follow-up.

   This Department has long had the authority to take (summary) action against producers who were dumping saltwater into the streams and onto the land, but until recently (about 1969) had left oil pollution up to the Louisiana Stream Control Commission. They have now become active also in oil spills.

7. Items Contained in Data Bank:

   a. Field location

   b. Company

c. Date and time

d. Amount of oil lost

e. Cause of incident

f. Corrective action taken

g. Size of sighted oil spill - length and width

h. Direction of movement

i. Weather conditions

j. By whom reported.

8. Time Span Covered by Study Data: Late 1969 through November 1971.

9. Volume of Data: There were 690 pieces of data in the file, all relating to oil or oil products. Of this total, approximately 300 are relevant to to this study. The remainder are related to maritime traffic (ships, boats, barges, docks, etc.), fuel spills, bilge pumping, product spillage, etc. Many were "John Doe" reports - that is, unknown source, unknown quantity, etc. A total of 707 reports (combined with the Baton Rouge File) were used in this study.

10. Limitations and General Comments on Data Bank: Data forms are extremely simple and lacking in the specific detail.

LOUISIANA DEPARTMENT OF CONSERVATION (BATON ROUGE FILE)

1. Data Bank Name: State of Louisiana
Department of Conservation
Division of Minerals
Headquarters Office File, Baton Rouge

2. Data Bank Location: Oil and Gas Division Building
P.O. Box 44275 Capitol Station
Baton Rouge, Louisiana 70804

3. Data Bank Structure: Data are presented on limited and simple standard forms. Data not computerized.

4. Scope: Data received and filed daily. All "John Doe" reports, as well as all reports of less than three barrels (as reported), are discarded. File is kept by operator names and all data over 1 year is deleted from the file. Form is that prescribed in a letter directive of October 28, 1970.

5. Reporting Requirements: See Item 7 of Louisiana Conservation Commission New Orleans File for data elements to be reported.

6. Purpose: Refer to Item 6, New Orleans File.

7. Items Contained in Data Bank: Refer to Item 7, New Orleans File.

8. Time Span Covered by Study Data: One year previous to October 15, 1971.

9. Volume of Data: There were 1105 spill reports in the file, with approximately 100 not relevant to this study. See New Orleans File.

10. Limitations and General Comments on Data Bank: Generally the same remarks as apply to the New Orleans data. Note the different time frame and different amount of the spill between those records here and those of the New Orleans bank. There is no doubt that some overlap. The New Orleans file is the most nearly complete for that district -- both over a longer time and covering some smaller spills.

MISSISSIPPI OIL AND GAS BOARD

1. Data Bank Name: State of Mississippi
   Oil and Gas Board File

2. Data Bank Location: Mississippi Oil and Gas Board
   State Office Buildings
   P. O. Box 1332
   Jackson, Mississippi 39205

3. Data Bank Structure: Reports by letter are required, but not in any specified format.

4. Scope: Letter reports from operators cover details on all fires which destroy oil or gas, details of any breaks or leaks in pipelines or tank overruns, and steps taken to correct situation. Amounts of oil spill are to be reported if loss exceeds 100 barrels. The letter file is the central data bank for the State of Mississippi.

   State Oil and Gas Board Order 245-56 provides rules for prevention of pollution of fresh waters and contamination of soils. However, no reporting is required in the enforcement procedures.

5. Reporting Requirements: Rule 17 of the Statewide Rules and Regulations sets forth the requirement for letter reporting immediately to the Board of fires, leaks, and blowouts.

6. Purpose: To gather information on petroleum production losses to protect public and private interests against waste in production and use of oil and gas.

7. Items Contained in Data Bank: General description of damage and the location, given by section, township, range, and property.

8. Time Span Covered by Study Data: December 1959 through November 1971.

9. Volume of Data: 202 spill events, all of which are crude oil (except for four condensate) spills. All were used in this study.

10. Limitations and General Comments on Data Bank: Data lacks the technical detail necessary for reliability analysis.

NEW MEXICO OIL CONSERVATION COMMISSION

1. Data Bank Name: State of New Mexico
   Oil Conservation Commission Rule 116 File

2. Data Bank Locations: The state is divided into four districts and each district maintains its own data bank.

3. Data Bank Structure: There are no forms required. Spills are reported by letter to the district office.

4. Scope: Not defined.

5. Reporting Requirements: New Mexico Oil Conservation Commission Rule No. 116 requires that all oil spills of 100 barrels or more be immediately reported in writing to the district office. New Mexico requires oil spill reports for purposes of inventory production, transfer, and storage of petroleum within the district.

6–7. Purpose and Items Contained in Bank: The requirements are that the amount of the spill, location, cause, and clean up, if any, be reported. Sometimes the repair action taken is also reported. New Mexico requires oil producers to report all movements of oil from one lease to another. These reports are filed with the spill data reports, making a large volume of data pertaining to oil transfer and/or spillage.

8. Time Span Covered: January 1968 through August 1971. Districts keep data only 5 years.

9. Volume of Data: 58 relevant reports. All were used in this study.

10. Limitations and General Comments: The reports are more for control of production and oil transfer than for pollution; therefore, they lack the technical detail necessary for reliability analysis.

OKLAHOMA CORPORATION COMMISSION

1. Data Bank Name: State of Oklahoma
   Corporation Commission
   Oil and Gas Conservation Division File
   Form 1036-Complaint (Informal)

2. Data Bank Location: Oklahoma Corporation Commission
   Oil & Gas Conservation Division
   380 Jim Thorpe Building
   Oklahoma City, Oklahoma

   Only the district offices maintain permanent files of their Form 1036-Complaint.

3. Data Bank Structure: Data are submitted on Form 1036-Complaint, which is a universal form used by the field inspectors to report all types of field violations of the Rules and Regulations.

4. Scope: Form 1036-Complaint is designed for reporting all infractions of the Rules and Regulations and not specifically for oil spills. Data depositories are maintained in each of the four districts.

5. Reporting Requirements: All reports of any commission rule violations are investigated and filed on Form 1036. Pollution or damage to any surface or underground fresh water is such a violation.

6. Purpose: To comply with the Rules and Regulations of the Oil & Gas Conservation Division.

7. Items Contained in Data Bank: Numerous identification items such as identity of violator, description of conditions, corrective action necessary, and time to correct.

8. Time Span Covered by Study Data: November 1967 through November 1971. The file contains very few reports in 1967, 1968 and 1969.

9. Volume of Data: A total of 399 spill events were relevant and used in this study.

10. Limitations and General Comments on Data Bank: Data lacks technical detail necessary to reliability analysis.

TEXAS RAILROAD COMMISSION

1. Data Bank Name: Texas Railroad Commission
   Oil and Gas Division File

2. Data Bank Location: Texas Railroad Commission
   Oil and Gas Division
   Corner 10th and Colorado Streets
   Drawer EE
   Austin, Texas 78711

3. Data Bank Structure: Data have been presented on standard forms since about June 1970. Prior to that, they were in narrative form by letter, or on some individual company forms. They are not computerized. The reports from each of the 12 districts are separated into oil pipeline and producing operations spills.

4. Scope: The data is meant to include all reports of spills of crude oil, gas well liquids, or associated products lost in a quantity of more than five barrels.

5. Reporting Requirements: Form H-8, Crude Oil Loss Report is filed with the Railroad Commission District Office by operating company causing spill.

6. Purpose: The R. R. C. is required by law to: (a) prevent waste, and (b) prorate production, and (c) protect correlative rights. Form H-8 was designed for this purpose - to follow up and enforce rules against waste (spillage is one form) and to keep inventory of all oil produced so that proration is practiced and enforced. The use of this form as a tool to help stop pollution is a "newly acquired" useful function, and not necessarily intended at the outset.

7. Items Contained in Data Bank: Usually, only general information is given; details important to reliability study are rare.

8. Time Span Covered by Study Data: Approximately January 1, 1970 through November 1971. Headquarters file is regularly purged of data more than 2 years' old.

9. Volume of Data: 5170 spill events. 5094 records were used in this study.

10. Limits and General Comments on Data Bank: Hard, specific facts are few, and the main value of this, the largest collection of raw data found, is statistical use - indicating general and specific areas of problems only, and suggesting some general remedies. There are probably almost as many designs, or configuration of "systems, " and "subsystems" as pieces of data.

CALIFORNIA WESTERN OIL AND GAS ASSOCIATION

This source was contacted, but they indicated that no records were available that would be pertinent to this study.

ALBERTA OIL AND GAS CONSERVATION BOARD

1. Data Bank Name: Alberta Oil and Gas Conservation Board
Drilling and Production Monthly Pollution Summaries.

2. Data Bank Location: Oil and Gas Conservation Board
603 Sixth Avenue, S. W.
Calgary, Alberta, Canada

3. Data Bank Structure: No standardized format is used among the field offices or by the same field offices from month to month.

4. Scope: Pollution summaries are submitted monthly from each of five field offices. Pipeline spills do not fall under the jurisdication of this office; they are handled by the Alberta Department of Mines and Minerals. The summaries appear to be based on the results of investigations instigated by complaint rather than formally required submissions by the cognizant oil company. The field offices which provide the summaries to this central bank may possibly have more detailed information, although this is currently unknown. The related field offices are:

    - Medicine Hat
    - Red Deer
    - Black Diamond
    - Edmonton
    - Drayton Valley

5. Reporting Requirements: Any operator of a well or an oil sands scheme is required to immediately report (a) any fire at a battery, well, storage tank, or pit where the loss exceeds 100 barrels of oil; (b) any break or leak at an installation used in the operation of an oil sands scheme from which the loss exceeds 100 barrels of oil. In a report of such accidents, the location of the well, tank, pit, or line break is required to be given. The report is sent to the Oil and Gas Conservation Board at the address in Item 2. This requirement is included in a paragraph of the Oil and Gas Conservation Regulations.

6. Purpose: To effect conservation of petroleum products, prevent waste, control pollution, and secure the observance of safe and efficient field practices. Data are collected, summarized, evaluated, and published in support of these goals.

7. Items Contained in Data Bank: The data bank includes odor complaints, oil and salt water spills, and black smoke contraventions.

8. Time Span Covered by Study Data: The data cover the period from January 1970 through July 1971.

9. Volume of Data: The bank includes 419 reports of crude oil spillage. It does not include spills of other products. 235 reports were used in this study.

10. Limitations and General Comments on Data Bank: The data bank appears to be in a state of flux as far as presentation format is concerned. The data are not conducive to problem analysis below subsystem level or cause.

ALBERTA DEPARTMENT OF MINES AND MINERALS

1. Data Bank Name: Province of Alberta
Department of Mines and Minerals
Pipeline Spill File

2. Data Bank Location: Department of Mines and Minerals
Edmonton, Alberta
Canada

3. Data Bank Structure: The data bank consists of telephone messages and letter reports. Access to the records without a court order was not permitted; therefore, the above description is all that could be ascertained from conversation.

4-5. Scope and Reporting Requirements: The permittee or licensee is required to inform the Superintendent of Pipelines or an inspector as soon as possible when a break in a pipeline occurs. If the break is on Crown land or in a forested area, the operator is required to notify the Department of Lands and Forests of the location and the quantity of oil spilled. After the break is repaired, the permittee or licensee is required to submit a written report to the Superintendent of Pipelines showing:

a. The time the break occurred

b. Quantity of substance lost

c. The conditions that caused or contributed to the break.

6. Purpose: Not defined.

7. Items Contained in the Data Bank: The data bank includes gas and other petroleum product losses as well as crude oil. It is not known if other data are included.

8. Time Span Covered by Study Data: Not specified.

9. Volume of Data: Not specified. None were used in this study.

10. Limitations and General Comments on Data Bank: Insufficient knowledge of the data bank precludes discussion.

APPENDIX D

TABULATION OF OIL SPILL RECORD DATA

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APPENDIX D

TABULATION OF OIL SPILL RECORD DATA

D.1 INTRODUCTORY SUMMARY

The spill prevention program described in this report relies strongly on the spill data presented in this appendix. The spill data are essential to the analysis of Appendix E, and identify the types and frequencies of failures of equipments, personnel, and procedures resulting in oil spills. Additional data for Gulf OCS safety shutdown devices are given in Appendix J. This appendix provides a basis to evaluate the spill prevention program in terms of the spill data used.

A spillage or noncontainment of crude oil or condensate was the criterion used to define a petroleum system failure to determine the types of data required for the study. Spills related to marine transportation were excluded in accordance with program guidelines. It was found that primary sources of oil spill reports were data banks maintained by various State and Federal agencies, which contained spill reports submitted in response to individual agency requirements. Most of the requirements relate to regulating traffic in the petroleum products and to protecting the public interest. Generally, a minimum of technical detail is required.

A review of potential spill data sources was made and contacts at some of these organizations revealed other possible sources. The initial visits to collect spill records were made in the Washington, D.C. area at the Environmental Protection Agency, Department of Transportation, U.S. Coast Guard, and U.S. Geological Survey. Since spills from marine transportation sources were not sought, the extensive USCG data bank contained only a few events pertinent to this study. These were evaluated but not entered into the study's computer file.

Over 15,000 oil spill events were reviewed during this study. The majority of the records had been generated in the 1970-1971 period as a result of increased public and political interest in environment preservation. Of these, 8473 were found to apply to the study objectives and were extracted from the data banks. Of the 20 data sources examined, seven used prepared forms required to be submitted to an agency office when a spill occurred. Only narrative reports or summary records were kept in the remainder of the sources. Summary descriptions of each source data bank are contained in Appendix C. The volume of data collected from the individual sources varied widely, as did the relative sizes of the data banks.

As information was gathered it became evident that the oil spill data, while containing useful information, were submitted in response to requirements not necessarily aimed at deriving specific reliability parameters of petroleum systems.

Some of the deficiencies of the data included:

1. Equipment failure data not resulting in spills were totally lacking; all the information collected and analyzed consisted of spill event data.
2. Equipment population could not be identified.
3. Equipment identification codes or nomenclature were not standardized.
4. Equipment configurations could not be determined.
5. Maintenance actions and repair time information were not available.
6. There were many instances of inconsistent equipment and event nomenclature.
7. Often the effect of an oil spill was identified but not the cause.
8. Cost of repair parts or cleanup operations was not available.

In spite of these deficiencies, the data did support analysis leading to an identification of the most common failure points leading to oil spillage. This analysis is documented in Appendix E.

D.2 TABULATIONS OF OIL SPILL RECORD DATA

Tables D-1 through D-15 contain data taken from each data source used in this study. The data are arranged such that the subsystem elements of the Gathering/Distribution Drilling, and Production Systems are shown across the top and the components are listed down the page. The elements and components were derived from the systems description in Appendix B, as documented in Appendix K. The number of spills is indicated in the appropriate column under the equipment involved and in the row of the responsible component. Columns of totals are shown with the heavier-lined borders. Figure D-1 summarizes the source data given in Tables D-1 through D-15.

	Number of Records Used	Type of Report		Table Number	Systems Reported*
		Form	Narrative		
Federal					
EPA Headquarters - OHM File	108		X	D-1	G/D, D, P
EPA Anchorage, Alaska	68		X	D-2	D, P
DOT/FRRC - Pipeline Carrier Accident Reports	802	X		D-3	G/D
U.S. Geological Survey, Conservation Division, Washington, D.C. Office	633	X		D-4	G/D, D, P
States					
California - Department of Fish and Game Commission	63		X	D-5	G/D, P
California - Water Quality Control Board	19	X		D-6	G/D, D, P
California - Division of Oil and Gas	40		X	D-7	G/D, D, P
California - City of Long Beach, Department of Oil Properties	30		X	D-8	G/D, D, P
Colorado - Department of Health, Water Pollution Control Division	10	X		D-9	G/D, P
Louisiana - Department of Conservation, Division of Minerals	707	X		D-10	G/D, P
Mississippi - Oil and Gas Board	202		X	D-11	G/D, P
New Mexico - Oil Conservation Commission	58		X	D-12	G/D, P
Oklahoma - Corporation Commission Oil and Gas Conservation Division	399	X		D-13	G/D, D, P
Texas - Railroad Commission Oil and Gas Division	5094	X		D-14	G/D, D, P
Other					
Alberta, Canada - Alberta Oil and Gas Conservation Board	235		X	D-15	G/D, D, P

*G/D = Gathering/Distribution Systems
D = Drilling Systems
P = Production Systems

Figure D-1. Source Data Summary

The remaining tables (D-16 through D-29) present various compilations of the source data, as indicated below:

- Tables D-16 and D-17 present components versus system elements for offshore moderate spills and onshore major spills, respectively.
- Tables D-18 through D-20 present the spill data tabulated for the Gathering/Distribution, Drilling, and Production Systems, respectively, to show the causes versus components involved for all spills.
- Tables D-21 through D-24 present data for causes versus components involved for onshore major spills and offshore moderate spills for the Gathering/Distribution and Production Systems.
- Tables D-25 and D-26 present the system elements versus causes for all major spills and offshore moderate spills, respectively.
- Table D-27 persents component versus spill quantity for all spills grouped by system into minor, moderate, and major spill categories.
- Tables D-28 and D-29 present data similar to that in Table D-27, but specifically for the Gathering/Distribution and Production Systems, respectively, and further grouped by onshore and offshore systems.

The numbers in the column headers and the CODE column are described in Appendix K and relate to the corresponding items in the computerized data bank established for correlating and analyzing the collected data for presentation in this report.

Table D-1. EPA Headquarters - OHM File

		GATHERING/DISTRIBUTION SYSTEM															DRILLING SYSTEM					
Component \ Element	Code	10000 Gathering/ Distribution System	11000 Pipeline Subsystem	11100 Pipe	11200 Scraper Trap Equipment	11400 Submerged Water Crossing	12000 Storage Subsystem	12100 Tank	12300 Tank Associated Equipment	13000 Pump Station Subsystem	13300 Pump	13B00 Pressure Controllers	13D00 Valve	13E00 Valve Operating Equipment/ Controls	Gathering/ Distribution System Totals	20000 Drilling System	21000 Well Subsystem	21200 Casing String	23100 Derrick Platform	25000 Drill String Subsystem	Drilling System Totals
Not Identified	00	4		2				4							10			1	1	1	3
Disc, Rupture	16																				
Pipe	46			55		1			1						57						
Riser	55																				
Tank Shell	67							1							1						
Valve	74																				
Valve, Ball	76																				
Valve, Dump	82																				
TOTALS		4		57		1		5	1						68			1	1	1	3

		PRODUCTION SYSTEM																			
Component \ Element	Code	30000 Production System	31000 Well Subsystem	32000 Well Head Subsystem	32100 Casing Head Equipment	33100 Flow Line Equipment	33600 Pumps	34000 Separation Subsystem	34500 Scrubber Equipment	35000 Treater Subsystem	351000 Heater Treater	35600 Skimmer	36000 Local Storage Subsystem	36100 Tanks	36200 Tank Associated Equipment	36300 Sump System	38000 Safety Shutdown & Alarm Subsystem	39000 Water Disposal Subsystem	Production System Totals	Bank Totals
Not Identified	00	25	1			1	1	1		1	1								31	44
Disc, Rupture	16				1														1	1
Pipe	46														1				1	58
Riser	55					1													1	1
Tank Shell	67																			1
Valve	74	1										1			1				2	2
Valve, Ball	76																			
Valve, Dump	82																		1	1
TOTALS		26	1		1	2	1	1		1	1	1			2				37	108

Table D-2. EPA Anchorage, Alaska

Component \ Element	CODE	DRILLING SYSTEM		PRODUCTION SYSTEM																
		20000 Drilling System	Drilling System Totals	30000 Production System	31000 Well Subsystem	32000 Well Head Subsystem	33100 Flowline Equipment	34000 Separation Subsystem	34500 Scrubber Equipment	35000 Treater Subsystem	35100 Heater Treater	35600 Skimmer	36000 Local Storage Subsystem	36100 Tanks	36200 Tank Associated Equipment	36300 Sump System	38000 Safety Shutdown & Alarm Subsystem	39000 Water Disposal Subsystem	Production System Totals	Bank Totals
Not Identified	00	3	3	7		2	7	1		6	3	4		2	2	1	1	3	39	42
Coupling	12						1												1	1
Fasteners	18						1												1	1
Flange	20						4												4	4
Pig	45						1												1	1
Pipe	46						1												1	1
Pump	49																	1	1	1
Sensor, Hi-Level	61							1	1		3							1	6	6
Valve	74							1						1	2				4	4
Valve, Ball	76																		2	2
Valve, Check	80						2								1				1	1
Valve, Dump	82							3		1									4	4
TOTALS		3	3	7		2	17	6	1	7	6	4		3	5	1	1	5	65	68

Table D-3. DOT/FRRC - Pipeline Carrier Accident Reports

		GATHERING/DISTRIBUTION SYSTEM													
Component \ Element	CODE	10000 Gathering/ Distribution System	11000 Pipeline Subsystem	11100 Pipe	11200 Scraper Trap Equipment	12000 Storage Subsystem	12100 Tank	12300 Tank Associated Equipment	13000 Pump Station Subsystem	13100 Pump	13B00 Pressure Controllers	13D00 Valve	13E00 Valve Operating Equipment/ Controls	Bank Totals
Not Identified	00				1		9	1	1	5	1	5	1	24
Coupling	12			2				1	1					4
Fasteners	18									1				1
Fittings	19			11					1	1				13
Flange	20			2						1				3
Foundation	24			1										1
Gasket	25			1						3			1	5
Gasket, Ring	26		1											1
Gland, Packing	28									1				1
Meters	40						1	1						2
Nipple	41			2										2
Pig	45													
Pipe	46			687						1				688
Plug, Bull	48			3										3
Pump	49							1						1
Seals	59							1		2				3
Seam	60			2										2
Sensor, Hi-Level	61													
Switches	66			1										1
Tees	68			1										1
Threads	69			2					1	1				4
Valve	74		2	10			2	5	2					21
Valve, Ball	76													
Valve Check	80													
Valve Dump	82													
Valve, Gate	83			3								1		4
Valve, Pressure Relief	86						1							1
Welds	89			13					2					15
Strainer	99								1					1
TOTALS Total		0	3	741	1	0	13	10	9	16	1	6	2	802

Table D-4. California Department of Fish and Game Commission

		GATHERING/DISTRIBUTION SYSTEM						PRODUCTION SYSTEM														
Element / Component	Code	10000 Gathering/ Distribution System	11000 Pipeline Sub-system	11100 Pipe	12000 Storage Sub-system	12100 Tank	Gathering/Distribution System Totals	30000 Production System	32000 Well Head Subsystem	32500 Rod Pump	33000 Gathering Subsystem	33100 Flow Line Equipment	34000 Separation Subsystem	35000 Treater Subsystem	35600 Skimmer	36000 Local Storage Subsystem	36200 Tank Associ-ated Equipment	36300 Sump System	39000 Water Disposal Subsystem	39200 Precipitator	Production System Totals	Bank Totals
Not Identified	00	3					3	4					1		7			1		1	14	17
Coupling	12											2									2	2
Pipe	46			32			32										1				1	33
Rods	56									2											2	2
Tank Shell	67					1	1															1
Valve	74	1					1	7													7	8
Totals		4		32		1	37	11		2		2	1		7		1	1		1	26	63

		GATHERING/ DISTRIBUTION SYSTEM							DRILLING SYSTEM																						
ELEMENT / COMPONENT	CODE	11000 PIPELINE SUBSYSTEM	11100 PIPE	11500 SUBMERGED CROSSING LAND	12300 TANK EQUIPMENT	13100 PUMP	13400 MANIFOLD	GATHERING/DISTRIBUTION SYSTEM TOTALS	20000 DRILLING SYSTEM	21000 WELL SUBSYSTEM	21100 HOLE	24300 MUD PUMP	25000 DRILL STRING SYBSYSTEM	25200 KELLY	26300 ANNULAR (BAG TYPE) BOP	26400 DOWN HOLE BOP	DRILLING SYSTEM TOTALS	30000 PRODUCTION SYSTEM	31000 WELL SUBSYSTEM	31200 CASING STRING	31300 PRODUCTION TUBING	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32300 CHOKE FIXED	33100 FLOW LINE EQUIPMENT	33400 MANIFOLD	33600 PUMPS	33700 AUTOMATIC CONTROL EQUIPMENT	34000 SEPARATION SUBSYSTEM	34100 SEPARATORS,
Not Identified	00	7	3	1	1		1		13	1	2			2	1	1	1	8	18	7			1			1	11	1	3		3
Blowcase–Salt Water	03																		8												
Choke Bean	07																														1
Choke Body	08											1						1					3			7	2				
Coupling	12		1				1		2										1										1		
Diaphragm	15																														
Disc–Rupture	16												1					1	4								1				1
Ells	17																		1								1				
Fittings	19																														
Flange	20																		1								2		1		
Float	21																		1									1			
Gasket	25	1		1				1	3										1										1		
Gauges	27			1					1																		1				
Gland–Packing	28												1					1							1	1			2		
Glass–Sight	29																														
Header	30																		1												
Hose	34																		1									2	1		
Nipple	41		1						1																		1				1
O–Ring	43			1					1										1				1								
Packers	44																				1								1		
Pig	45			2					2																						
Pipe	46		1	2			2		5	2								2	4								24	1	6	1	
Piston	47																												1		
Plug–Bull	48																														
Pump	49	9	1						10																				2		
Regulator–Pressure	52																														
Riser	55	1							1																		3				
Screen	58																														
Seals	59																												1		
Sensor Hi–Level	61																		1												
Sensor Lo–Level	62																														
Sensor Hi–Pressure	63																						3								
Sensor Lo–Pressure	64																										1				
Switches	66																												2		
Tees	68																														1
Tubing Hanger	70																					1									
Union	72																														
Valve	74			3		1			4										2	1			1		1		1	2	1		
Valve–Back Pressure	75																		2												
Valve–Ball	76																														
Valve–Body	78																						1				1				1
Valve–Bypass	79																														
Valve–Check	80	2							2										1									1	1		
Valve–Dump	82																														
Valve–Needle	84																		1	1		1									
Valve–Pressure Relief	86																		5			1		1			1		2		
Valve–Trim	87																														
Vessel–Pressure	88																														
Motor	91																		2										1		
Control	93																		1												
TOTALS		20	7	11	1	1	4	1	45	3	2	1	2	2	1	1	1	13	57	9	1	2	10	2	2	9	50	8	27	1	8

A

Table D-5. Geological Survey, Conservation Division, Washington, D.C. Office

PRODUCTION SYSTEM																																		
33400 MANIFOLD	33600 PUMPS	33700 AUTOMATIC CONTROL EQUIPMENT	34000 SEPARATION SUBSYSTEM	34100 SEPARATORS, HIGH PRESSURE	34200 HIGH PRESSURE SEPARATOR CONTROLS	34300 SEPARATORS, LOW PRESSURE	34400 LOW PRESSURE SEPARATOR CONTROLS	34400 LOW PRESSURE SEPARATOR CONTROLS	34500 METERING	34600 SCRUBBER CONTROLS	35000 TREATER SUBSYSTEM	35100 HEATER TREATER	35200 HEATER–TREATER CONTROLS	35300 CHEMICAL–ELECTRICAL TREATER	35500 GUN BARREL	35600 SKIMMER	35700 FREE WATER KNOCKOUT	36000 STORAGE SUBSYSTEM	36100 TANKS	36200 TANK EQUIPMENT	36300 SUMP SYSTEM	37000 CUSTODY TRANSFER SUBSYSTEM	37100 PUMPS	37200 PUMP CONTROLS	37300 METER EQUIPMENT	37600 PROVER TANK	38000 SAFETY SUBSYSTEM	38100 ENERGY SOURCE	38200 DISTRIBUTION EQUIPMENT	38500 SUBSURFACE SAFETY VALVE	38600 HI–LO PRESSURE VALVE	38800 WATER DISPOSAL SUBSYSTEM	PRODUCTION SYSTEM TOTALS	BANK TOTALS
11	1	3		3			21	2	6	1	1	2		2	1	11	2		19	1	26		3	1			8	2	2	1	1	3	161	182
																																	8	8
				1																													1	1
2																																	12	13
		1																1															3	5
													1																				1	1
1				1			12							1			1		2														22	23
1					1		1																										4	4
																					1												1	1
2		1					1											1			1												7	7
	1							2								1					1												6	6
		1										1										1											4	7
1								1														1											3	4
		2																		1													5	6
																1																	1	1
																																	1	1
	2	1																1		3													8	8
1				1			1														1												4	5
																									1								3	4
		1																															2	2
																																	0	2
24	1	6	1					1	1			3		1	1	4			1	2	6												56	63
		1																															1	1
																				1													1	1
		2														1	1	1		2	24					1							32	42
									1			1																					2	2
3																																	3	4
																1																	1	1
		1																															1	1
						1	13	5	5	2		2			1	2	1		3	11	9					1	4						61	61
							3										1			1							1						6	6
						2		2									1																8	8
1																																	1	1
		2																															2	2
				1	1																												2	2
																																	1	1
							1																										1	1
1	2	1					2		1							1				1	4						7						25	29
							1																										3	3
												1									1												2	2
1				1			1																										4	4
																					1												1	1
	1	1									1										2	1											8	10
					4		18	1	4			5		2	3	5	2																44	44
																																	3	3
1		2				1	12		2			1					2																27	27
							3														1												4	4
							2								1																		3	3
		1																															3	3
							1	2							2	1				1	3						1						12	12
50	8	27	1	8	6	4	93	16	20	3	2	16	1	6	9	28	11	4	25	24	81	3	3	1	1	2	21	2	2	1	1	3	575	633

B

Table D-6. California Water Quality Control Board

		GATHERING/ DISTRIBUTION SYSTEM			DRILLING SYSTEM			PRODUCTION SYSTEM										
Element / Component	Code	11100 Pipeline Subsystem	11100 Pipe	Gathering/Distribution System Totals	21000 Well Subsystem	21100 Hole	Drilling System Totals	32000 Well Head Subsystem	32100 Casing Head Equipment	32200 Tubing Head Equipment	33000 Gathering Subsystem	33100 Flow Line	36000 Local Storage Subsystem	36200 Tank Associated Equipment	37000 Custody Transfer Subsystem	37100 Pumps	Production System Totals	Bank Totals
Not Identified	00		1	1		1	1											2
Hose	34									1							1	1
Pipe	46		10	10														10
Plug, Bull	48								1								1	1
Valve	74									1		1		2		1	5	5
TOTALS			11	11		1	1		1	2		1		2		1	7	19

Table D-7. California Division of Oil and Gas

Component \ Element	Code	11000 Pipeline Subsystem	11100 Pipe	14000 Safety Subsystem	Gathering/ Distribution System Totals	24000 Mud Subsystem	24100 Mud Pit	Drilling System Totals	30000 Production System	32000 Well Head Subsystem	32500 Rod Pump	32700 Gas Lift	33000 Gathering Subsystem	33100 Flow Line	33600 Pumps	35000 Treater Subsystem	35600 Skimmer	3600 Local Storage Sub-system	36100 Tanks	36200 Tank Associated Equipment	36300 Sump	Production System Totals	Bank Totals
		GATHERING/ DISTRIBUTION SYSTEM				DRILLING SYSTEM			PRODUCTION SYSTEM														
Not Identified	00			1	1				3								1		1		2	7	8
Box, Stuffing	05										1											1	1
Pipe	46		8		8		1	1						5								5	14
Pump	49											1										1	1
Rods	56														1							1	1
Rod, Polished	57										1											1	1
Tank Shell	67																				5	5	5
Valve	74																		2	1		3	3
Valve, Check	80													2						1		3	3
Valve Pressure Relief	86		1		1															1		1	2
Oil/Leg	96																			1		1	1
TOTALS			9	1	10		1	1	3		2	1		7	1		1		3	4	7	29	40

		GATHERING/ DISTRIBUTION SYSTEM				DRILLING SYSTEM										
Element Component	Code	10000 Gathering/ Distribution System	11000 Pipeline Subsystem	11100 Pipe	Gathering/Distribution System Totals	20000 Drilling System	26000 BOP Subsystem	26200 Blind Ram BOP	26300 Annular BOP	Drilling System Totals	30000 Production System	31000 Well Subsystem	31400 Downhole Assembly	32000 Well Head Subsystem	32200 Tubing Head Assembly	32500 Rod Pump
Not Identified	00	2			2	2			1	3	6					
Coupling	12															
Float (Oil/Water)	23															
Gasket	25															
Packers	44												1			
Pipe	46			2	2											
Pump	49															
Rods	56															1
Sensor Hi-Level	61															
Union	72															
Valve	74															
Valve, By Pass	79															
Valve, Dump	82															
Valve, Pressure Relief	86														1	
Control	93							1		1						
TOTALS		2		2	4	2		1	1	4	6		1		1	1

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Table D-8. California - City of Long Beach, Department of Oil Properties

PRODUCTION SYSTEM																				
32000 Well Head Subsystem	32200 Tubing Head Assembly	32500 Rod Pump	33000 Gathering Subsystem	33100 Flow Line Equipment	34000 Separation Subsystem	34300 Low Pressure Separator	35000 Treater Subsystem	35200 Heater Treater Control	35400 Chemical-Electric Controls	35600 Skimmer	35700 Precipitator	36000 Local Storage Subsystem	36100 Tanks	36200 Tank Associated Equipment	38000 Safety Shut-down and Alarm S/S	38500 Electrical Equipment	39000 Water Disposal Subsystem	39100 Power	Production System Totals	Bank Totals
						1				1			1						9	14
								1											1	1
										1									1	1
																		1	1	1
																			1	1
				1															1	3
										1									1	1
		1																	1	1
																1			1	1
				1															1	1
														1					1	1
									1										1	1
											1								1	1
	1																		1	1
																				1
	1	1		2		1		1	1	3	1		1	1		1		1	22	30

B

Table D-9. Colorado Department of Health, Water Pollution Control Division

Element / Component	Code	GATHERING/DISTRIBUTION SYSTEM: 10000 Gathering/ Distribution System	11000 Pipeline S/S	11500 Submerged Crossing Land	Gathering/ Distribution Totals	PRODUCTION SYSTEM: 36000 Local Storage Subsystem	36400 Firewall	Production System Totals	Bank Totals
Not Identified	00	1			1		1	1	2
Pipe	46			8	8				8
TOTALS		1		8	9		1	1	10

		GATHERING/DISTRIBUTION SYSTEM																											
ELEMENT COMP	Code	10000 Gathering/ Distribution System	11000 Pipeline Sub-System	11100 Pipe	11200 Separator Trap Equipment	11400 Submerged Water Crossing	12100 Tank	12300 Tank Equipment	13000 Pump Station SubSystem	13100 Pump	13300 Reciprocating Pump	15000 Gathering Pipeline SubSystem	Gathering/Distribution System TOTALS	30000 Production System	31300 Production Tubing	32000 Well Head Equipment	32100 Casing Head Equipment	32200 Tubing Head Equipment	32300 Choke, Fixed	32700 Gaslift Equipment	33000 Gathering SubSystem	33100 Flow Line Equipment	33400 Manifold Equipment	33600 Pumps	34000 Separation SubSystem	34100 Separator Hi-Pressure	34200 Hi-Pressure Separator Controls	34300 Separator Lo-Pressure	34400 Lo-Pressure Separator Controls
Not Identified	00	2		13	1		1						17	25	1	3	1		5		1	52		4	15	1	1	3	
Bell, Alarm	1																								1				
Blowcage- Salt Water	3													1															
Box-Stuffing	5															1													
Choke Body	8																		5										
Choke Target	9																		4										
Coupling	12																					2		1					
Detector-Heat	14																						1						
Diaphragm	15																						1						
Disc-Rupture	16																								9	2		7	1
Ell	17																					2							
Fasteners	18																												
Fittings	19																					1							
Flange	20													1		2													
Foundation	24																												
Gasket	25																							2					
Gauges	27																												
Gland-Packing	28									1	1		2											3				1	
Glass-Sight	29																												
Header	30																						3						
Heater	31																												
Hose	34													1								4	1						
Liner	39																												1
Meters	40													1															
Nipple	41																					3							
O-Ring	43																		1		1								
Packers	44													1															
Pig	45											1	1																
Pipe	46			3		1		1	1			3		1		2						109		1	3	1			
Plug-Ball	48															2	2					2		1					
Pump	49		1										1	2										2					
Riser	55															1		1	1	1	1	2							
Seals	59																							1					
Seam	60																												
Sensor Hi-Level	61																								3				
Sensor Lo-Level	62																												
Sensor Lo-Pressure	64																												
Switches	66																							1					
Tees	68																			1		2							
Unions	72																					3	1						
Valve	74			1	1								2	2		3						4		1	2				
Valve-Back Pressure	75																								1			1	
Valve-Check	80																					3						1	
Valve, Control	81															1													
Valve-Dump	82													1											22	2	4	4	7
Valve-Gate	83			1									1																
Valve-Needle	84																									1			
Valve-Pressure Relief	86																					1			4	1			1
Fire Tube	92																												
Control	93																								2				
Tank-Test	95													3		1													
Water Line/Leg	97																								1				
Strainer	99																												
TOTALS		2	1	18	2	1	1	1	1	1	1	4	33	39	1	16	3	1	17	1	3	190	7	17	63	8	5	17	10

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Table D-10. Louisiana Department of Conservation, Division of Minerals

PRODUCTION SYSTEM																																
34100 Separator Hi-Pressure	34200 Hi-Pressure Separator Controls	34300 Separator Lo-Pressure	34400 Lo-Pressure Separator Controls	34500 Scrubber	34600 Scrubber Controls	35000 Treater SubSystem	35100 Heater Treater	35200 Heater Treater Controls	35300 Chemical-Electrical Treater	35400 Chemical-Electrical Treater Controls	35500 Gun Barrel	35600 Skimmer	35700 Free Water Knockout	36000 Storage SubSystem	36100 Tanks	36200 Tank Equipment	36300 Sump	36400 Firewall	37000 Custody Transfer Equipment	37100 Pumps	37200 Pump Controls	37400 Manifold	37600 Prover Tank	37700 Power	38000 Safety Subsystem	38300 Sensing Or Detecting Equipment	38400 Monitor And Alarm Panel	39000 Water Disposal SubSystem	39100 Power	39200 Precipitator	Production System TOTALS	Bank TOTALS
1	1	3		3	1	3	12	2	1		4	8	6	8	21	4	32	4	1	3			2	1	4	1		2	1	1	237	254
													2			1	1									2	1				9	9
																															1	1
																															1	1
																1															6	6
																															4	4
																															3	3
																															1	1
																															1	1
2		7	1			1	3																								23	23
																															2	2
																1			1												2	2
																															1	1
							2																								5	5
																															0	0
																2															4	4
							1												1												2	2
																															3	5
		1																													1	1
																															3	3
							3																								3	3
														1		3															10	10
														1																	1	1
			1																												2	2
																															3	3
																															2	2
																															1	1
																															0	1
1				1								1		2	2	2	5											1			133	142
							1									11	2						1								23	23
									1																			1			6	7
																															4	4
																															1	1
															1																1	1
								1			1						2								2	1					10	10
													1																		1	1
												1																			1	1
																1					1									3	6	6
																															3	3
																1															5	5
							2					1			3	8						1									27	29
		1																													2	2
		1																													4	4
											1																				2	2
2	4	4	7	3		5	18	1	1	2	1	3	6			1														1	82	82
																															0	1
1																															1	1
1			1	1		1										1	1														11	11
							2																								2	2
						1					1		2			1									1						8	8
																															4	4
							3									1															5	5
																	1														1	1
8	5	17	10	8	1	11	47	4	3	2	8	14	17	12	27	39	44	4	3	3	1	1	3	1	7	4	1	4	1	5	673	707

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		GATHERING/DISTRIBUTION SYSTEM												PRODUCT																
SYSTEM ELEMENT / COMPONENT	CODE	10000 TRANSPORTATION SYSTEM	11000 PIPELINE SUBSYSTEM	11100 PIPE	11200 TRAP EQUIPMENT	11400 SUBMERGED CROSSING WATER	12100 TANK	12200 TANK EQUIPMENT	13000 PUMP STATION SUBSYSTEM	13100 PUMP	13300 RECIPROCATING PUMP	15000 GATHERING PIPELINE SUBSYSTEM	GATHERING/DISTRIBUTION SYSTEM TOTALS	30000 PRODUCTION SYSTEM	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32300 CHOKE FIXED	33000 GATHERING SUBSYSTEM	33100 FLOW LINE EQUIPMENT	33400 MANIFOLD EQUIPMENT	33900 PUMP	34000 SEPARATION SUBSYSTEM	34100 SEPARATOR HI PRESSURE	34200 HI PRESSURE SEPARATOR CONTROL	34300 SEPARATOR LO PRESSURE	34400 LO PRESSURE SEPARATOR CONTROL	34500 SCRUBBER	34600 SCRUBBER CONTROL	35000 TREATER SUBSYSTEM
Not Identified	00	1		13			1						15	5	1			3	1	40		3	8		1	2		2	1	1
Bell–Alarm	01																						1							
Blowcase, Saltwater	03													1																
Choke Body	08																	4												
Choke Target	09																	3												
Coupling	12																			1										
Disc–Rupture	16																						7	2		3	1			
Ells	17																			2										
Fasteners	18																													
Flange	20														2															
Gasket	25																					1								
Gauges	27																													
Gland–Packing	28									1	1		2									3								
Glass, Sight	29																									1				
Header	30																				1									
Heater	31																													
Hose	34																			1										
Liner	39																													
Nipple	41																			3										
O–Ring	43																	1												
Pipe	46			3		1		1	1			2	8			2				90	1		2	1				1		
Plug, Bull	48														1		1			1		1								
Pump	49		1										1					1												
Riser	55														1															
Seam	60																													
Sensor, H.L.	61																													
Sensor, L.L.	62																													
Switches	66																													
Tees	68																	1		2										
Union	72																			1										
Valve	74			1	1								2		2					1		1	2							
Valve, Check	80																			1										
Valve, Dump	82												1										11	2		2	3	2		3
Valve, Press. Rel.	86																			1			2	1						1
Fire–Tube	92																													
Controls	93																						1							1
Water Line/Leg	97																													
Strainer	99																													
TOTALS		1	1	18	1	1	1	1	1	1	1	2	29	6	7	2	1	13	1	144	2	9	34	6	1	8	4	5	1	6

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Table D-10A. Louisiana Department of Conservation, Division of Minerals - Onshore Spills

PRODUCTION SYSTEM																															
33800 PUMP	34000 SEPARATION SUBSYSTEM	34100 SEPARATOR HI PRESSURE	34200 HI PRESSURE SEPARATOR CONTROL	34300 SEPARATOR LO PRESSURE	34400 LO PRESSURE SEPARATOR CONTROL	34500 SCRUBBER	34600 SCRUBBER CONTROL	35000 TREATER SUBSYSTEM	35100 HEATER TREATER EQUIPMENT	35200 HEATER TREATER CONTROL	35300 CHEM–ELECT TREATER	35400 CHEM–ELECT TREATER CONTROL	35500 GUN BARREL	35600 SKIMMER	35700 RECIPROCATING PUMP	36000 STORAGE SUBSYSTEM	36100 TANKS	36200 TANK EQUIPMENT	36300 SUMP EQUIPMENT	36400 FIRE WALL	37100 PUMPS	37200 PUMP CONTROLS	37400 MANIFOLD EQUIPMENT	37600 PROVER TANK	38000 SAFETY SUBSYSTEM	38300 SENSING/DETECTING EQUIPMENT	39000 WATER DISPOSAL SUBSYSTEM	39100 POWER	39200 PRECIPITATOR	PRODUCTION SYSTEM TOTALS	BANK TOTALS
3	8		1	2		2	1	1	8	1	1		3	3	1	8	13	4	17	4	2			1	1		2	1		138	153
	1																													1	1
																														1	1
																		1												5	5
																														3	3
																														1	1
	7	2		3	1				2																					15	15
																														2	2
																		1												1	1
									1																					3	3
1																		2												3	3
									1																					1	1
3																														3	5
				1																										1	1
																														1	1
									2																					2	2
																		1												2	2
																1														1	1
																														3	3
																														1	1
	2	1				1								1		2	1		2								1			104	112
1									1									6	2								1			14	14
																														1	2
																														1	1
																	1													1	1
										1																1			3	5	5
															1															1	1
																		1				1								2	2
																														3	3
																		1												2	2
1	2								1					1			2	7					1							18	20
																														1	1
	11	2		2	3	2		3	12			2		1	3			1											1	43	44
	2	1						1										1	1											7	7
									1																					1	1
	1							1					1		2			1												6	6
									3									1												4	4
																			1											1	1
[illegible]	34	6	1	8	4	5	1	6	32	2	1	2	4	6	7	11	17	28	23	4	2	1	1	1	1	1	4	1	4	403	432

B

Table D-10B. Louisiana Department of Conservation, Division of Minerals - Off-Shore Spills

		GATHERING/ DISTRIBUTION SYSTEM				PRODUCTION SYSTEM																																			
COMPONENT \ ELEMENT	CODE	10000 TRANSPORTATION SYSTEM	11200 TRAP EQUIPMENT	15000 GATHERING PIPELINE SUBSYSTEM	GATHERING/DISTRIBUTION SYSTEM TOTALS	20000 PRODUCTION SYSTEM	21300 PRODUCTION TUBING	22000 WELL HEAD EQUIPMENT	22100 CASING HEAD EQUIPMENT	22300 CHOKE FIXED	22700 GAS LIFT EQUIPMENT	23000 GATHERING SUBSYSTEM	23100 FLOW LINE EQUIPMENT	23400 MANIFOLD EQUIPMENT	23800 PUMP	24000 SEPARATION SUBSYSTEM	24100 SEPARATOR HI PRESSURE	24250 HI PRESSURE SEPARATOR CONTROL	24300 SEPARATOR LO PRESSURE	24400 LO PRESSURE SEPARATOR CONTROL	24800 SCRUBBER	25000 TREATER SUBSYSTEM	25100 HEATER TREATER	25200 HEATER TREATER CONTROL	25500 CHEM-ELECT TREATER	25800 GUN BARREL	25900 SKIMMER	25750 RECIPROCATING PUMP	26000 STORAGE SUBSYSTEM	26100 TANKS	26200 TANK EQUIPMENT	26300 SUMP EQUIPMENT	27000 CUSTODY TRANSFER SUBSYSTEM	27100 PUMP	27500 PROVER TANK	27700 POWER	28000 SAFETY SUBSYSTEM	28300 SENSING/DETECTING EQUIPMENT	28400 MONITOR/ALARM EQUIPMENT	28600 PRECIPITATOR	PRODUCTION SYSTEM TOTALS	Bank Totals
Not Identified	00	1	1		2	20	1	2	1	2			12		1	7	1		1		1	2	4	1		1	5	5		8		15	1	1	1	1	3	1		1	99	101
Bell-Alarm	01																											2			1	1						2	1		7	7
Box-Stuffing	05							1		1																															2	2
Choke Body	08									1																															1	1
Coupling	12												1		1																										2	2
Detector-Heat	14													1																											1	1
Diaphragm	15													1																											1	1
Disc-Rupture	16															2			4				1																		7	7
Fasteners	18																																1								1	1
Fittings	19												1																												1	1
Flange	20					1																	1																		2	2
Gasket	26														1																										1	1
Gauges	27																																1								1	1
Header	30													2																											2	2
Heater	31																						1																		1	1
Hose	34					1							3																1		2										7	7
Meters	40					1														1																					2	2
O-Ring	43											1																													1	1
Packers	44					1																																			1	1
Pig	45			1	1																																				0	1
Pipe	46			1	1	1		2					19		1	1														1	2	3									30	31
Plug-Bull	48										1		1																												2	2
Pump	49					2		1							2										1						5				1						12	12
Riser	56											1	2																												3	3
Seals	59														1																										1	1
Sensor H.L.	61															3										1						2					2				8	8
Sensor L.P.	64																										1														1	1
Switches	66														1																										1	1
Union	72												2	1																											3	3
Valve	74					2		1					3										1							1	1										9	9
Valve - Bk. Press.	75															1			1																						2	2
Valve-Check	80												2						1																						3	3
Valve-Control	81							1																		1															2	2
Valve-Dump	82					1										11		4	2	4	1	2	6	1	1	1	2	3													39	39
Valve-Needle	84																1																								1	1
Valve-Press. Rel.	86															2				1	1																				4	4
Fire-Tube	92																						1																		1	1
Controls	93															1						1															1				3	3
Test Tank	95					3		1																																	4	4
Water Line/Leg	97															1																									1	1
Strainer	99																																								0	0
TOTALS		1	1	2	4	33	1	9	1	4	1	2	46	5	8	29	2	4	9	6	3	5	15	2	2	4	8	10	1	10	11	21	3	1	2	1	6	3	1	1	270	274

Table D-11. Mississippi Oil and Gas Board

Element / Component	Code	GATHERING/DISTRIBUTION SYSTEM									PRODUCTION SYSTEM										
		11000 Pipeline Subsystem	11100 Pipe	12000 Storage Subsystem	12100 Tank	13000 Valve	13000 Pump Station Subsystem	13100 Pump	15000 Gathering Pipeline S/S	Gathering/ Distribution System Totals	32000 Well Head Subsystem	32100 Casing Head Equipment	33000 Gathering Subsystem	33100 Flow Line Equipment	35000 Treater Subsystem	35100 Heater Treater	36000 Local Storage Subsystem	36100 Tanks	36200 Tank Associated Equipment	Production System Totals	Bank Totals
Not Identified	00				5					5						2	1	1		4	9
Box, Stuffing	05											1								1	1
Coupling	12		1							1											1
Gasket	25		5						1	6											6
Hose	34		1							1											1
Meters	40				1					1											1
Pipe	46		156					1	10	167				1				1	1	3	170
Regulator, Pressure	52				1					1											1
Valve	74		1		1	3				5									2	2	7
Valve, Gate	83		2							2											2
Welds	89		2							2											2
Vent	94																		1	1	1
Totals			168		8	3		1	11	191		1		1		2	1	2	4	11	202

Table D-12. New Mexico Oil Conservation Commission

Element / Component	Code	GATHERING/DISTRIBUTION SYSTEM										PRODUCTION SYSTEM												
		11000 Pipeline Subsystem	11100 Pipe	11500 Submerged Crossing Land	12000 Storage Subsystem	12100 Tank	12300 Tank Associ-ated Equipment	13000 Pump Station Subsystem	13D00 Valve	13100 Pump	Gathering/Distribu-tion System Totals	33000 Gathering Subsystem	33100 Flow Line Equipment	34000 Separation Subsystem	34200 Separators High Controls	35000 Treater Subsystem	35100 Heater Treater	36000 Local Storage Subsystem	36100 Tanks	36200 Tank Associ ated Equipment	37000 Custody Transfer Sub-system	37100 Pumps	Production System Totals	Bank Totals
Not Identified	00															1	4		11				16	16
Coupling	12		2								2									1			1	3
Disc, Rupture	16														1								1	1
Gasket	25		1						1		2		1										1	3
Nipple	41												1										1	1
Pipe	46		13	3							16		1						1				2	18
Pump	49																					1	1	1
Tank Shell	67					1					1								4				4	5
Valve	74						1		1	1	3		3							1			4	7
Valve, Check	80						1				1													1
Valve, Dump	82																1			1			2	2
TOTALS			16	3		1	2		2	1	25		6		1	1	5		16	3		1	33	58

		GATHERING/DISTRIBUTION SYSTEM									DRILLING SYSTEM										
Element Component	Code	11000 Pipe Line Subsystem	11100 Pipe	11400 Submerged Crossing Water	11500 Submerged Crossing Land	13000 Pump Station Subsystem	13E00 Valve Operating Equipment/Control	13F00 Electric Power & Control	13100 Pump	Gathering/Distribution System Totals	20000 Drilling System	21000 Well Subsystem	21100 Hole	21200 Casing String	Drilling System Totals	30000 Production System	31000 Well Subsystem	31100 Bore	31200 Casing String	31300 Production Tubing	32000 Well Head
Not Identified	00		19			1			1	21	1				1	30	1	29	1	2	
Box, Stuffing	05																				
Coupling	12																				
Disc, Rupture	16																				
Fittings	19																				
Gland, Packing	28																				
Heater	31																				
Pipe	46		11	1	8					20			1	1	2				2		
Pump	49						1	1	3	5											
Switches	66																				
Tank Shell	67																				
Valve	74				1					1											
Valve, Check	80																				
Valve, Control	81																				
Valve, Dump	82																				
Vent	94																				
Oil/Leg	96															1					
TOTAL			30	1	9	1	1	1	4	47	1		1	1	3	31	1	29	3	2	

A

Table D-13. Oklahoma Commission, Oil and Gas Conservation Division

PRODUCTION SYSTEM

31100 Bore	31200 Casing String	31300 Production Tubing	32000 Well Head Subsystem	32100 Casing Head Equipment	32200 Tubing Head Equipment	32500 Rod Pump	33000 Gathering Subsystem	33100 Flow Line Equipment	33600 Pumps	34000 Separation Subsystem	34100 High Pressure Separators	34300 Low Pressure Separators	35000 Treater Subsystem	35100 Heater Treater	35200 Heater Treater Controls	35500 Gun Barrel	35700 Precipitator	36000 Local Storage Subsystem	36100 Tanks	36200 Tank Associated Equipment	36300 Sump System	39000 Water Disposal Subsystem	Production System Total	Bank TOTALS
29	1	2		1	30	2		2	3			4	2	3		4			85	9		1	209	231
				1	19	11																	31	31
					1																		1	1
												1											1	1
					1														1	2			4	4
									2														2	2
														5									5	5
	2				1			39						1			1		2				46	68
					1		1		11											1	1		15	20
									1														1	1
														2					5				7	7
								1			1	1		2					8	3			16	17
						1																	1	1
															1								1	1
														2						1			3	3
				1										1						3			5	5
																							1	1
29	3	2		3	53	14	1	42	17		1	6	2	16	1	4	1		101	19	1	1	349	399

B

ELEMENT / COMP	CODE	GATHERING/DISTRIBUTION SYSTEM																									
		10000 GATHERING/ DISTRIBUTION SYSTEM	11000 PIPE-LINE SUBSYSTEM	11100 PIPE	11200 SCRAPER TRAP EQUIPMENT	11300 SUBMERGED CROSSING WATER	11400 SUBMERGED CROSSING LAND	12000 STORAGE SUBSYSTEM	12100 TANK	12200 TANK EQUIPMENT	12300 PUMP SUBSYSTEM	12400 METERING EQUIPMENT	12500 VALVE	12600 VALVE OPERATING EQUIPMENT/CONTROLS	12700 ELECTRIC POWER & CONTROL	12800 DRAINAGE SYSTEM	13100 PUMP	13200 CENTRIFUGAL PUMP	13300 RECIPROCATING PUMP	13400 MANIFOLD	14000 SAFETY SUBSYSTEM	14100 FLOW INDICATING EQUIPMENT	15000 GATHERING PIPELINE SUBSYSTEM	15100 GRAVITY	15200 SUCTION	15300 PRESSURE	GATHERING/DISTRIBUTION SYSTEM TOTALS
Not Identified	00	6		253	6				28	1	2		1				6			1		1	1	1			306
Blowcase-Salt Water	03																										
Box – Stuffing	05																										
Cable	06																										
Choke Body	08																										
Coil	10																										
Coupling	12			19		1	1			1													4	1			27
Diaphragm	15																										
Disc-Regulators	16												1														1
Ells	17																										
Fasteners	18																2										2
Fittings	19			13																			5	1			19
Flange	20			8																			3	2			13
Float	21																			1							1
Foundation	24								1																		1
Gasket	25			14									5				1			1			5			1	27
Gauge	27																										
Gland-Packing	28																9	1	1	1							12
Glass-Sight	29																										
Header	30		1						1	1							1										4
Heater	31																										
Hose	34								2																		2
Joint-Blast	35			1																							1
Liner	39																										
Meters	40								1			1															2
Nipple	41			7									1				9						4				21
O-Ring	43			1																							1
Packers	44																1										1
Pig	45																										
Pipe	46	1	2	1638	2	3	28	3	5	7	6					2	5						673	66	39	6	2485
Piston	47																										
Plug-Bull	48			3																			2		1	1	7
Pump	49		1						1						1		2										5
Recorders	50																										
Regulator Pressure	52																										
Relay-Electrical	53																										
Riser	55			3													1										4
Rods	56																2										2
Rod-Polished	57																										
Seals	59				2												2										4
Seam	60																						1				1
Sensor Hi-Level	61																										
Sensor Hi-Pressure	63																										
Swage	65			1																			1				2
Switch	66																										
Tank Shell	67								3																		3
Tee	68			3																			2				5
Thread	69			4																							4
Tubing-Instrument	71			1							1						1					1					4
Union	72			1																							1
Union Flange	73																						1				1
Valve	74			12	2				2	5	1	1		1			6		1				9				40
Valve-Back Pressure	75																										
Valve-Body	78																										
Valve-Bypass	79									1			1				2										4
Valve-Check	80	1	1	22					4	22			1				1			1			9	2	1		65
Valve-Control	81			1																							1
Valve-Dump	82																										
Valve-Gate	83		1	9	1					4			5										7				27
Valve-Plug	85																										
Valve-Pressure Relief	86										1												1				2
Vessel-Pressure	88																1										1
Welds	89			5																			4				9
Motor	91			1					1								1										3
Fire Tube	92																										
Control	93															1	2										3
Vent	94																										
Tank-Test	95																										
Oil/Line	96																										
Water Line/Line	97																										
Fuel Line/Supply	98																										
Strainer	99											2					8										10
TOTALS		8	6	2020	13	4	29	3	49	42	11	4	16	1	1	3	63	1	2	6		1	732	73	41	8	3136

ELEMENT / COMP	CODE	DRILLING SYSTEM																
		20000 DRILLING SYSTEM	21100 HOLE	21200 CASING STRING	24000 MUD SUBSYSTEM	DRILLING SYSTEM TOTALS	30000 PRODUCTION SYSTEM	31000 WELL-SUBSYSTEM	31100 BORE	31200 CASING STRING	31300 PRODUCTION TUBING	31400 DOWN HOLE EQUIPMENT	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32300 CHOKE FIXED	ROD PUMP	HYDRAULIC LIFT
Not Identified	00	1	2	1	1	5	9	4	2	2	1	1	5	2		1		
Blowcase-Salt Water	03																	
Box – Stuffing	05										1		10	3	4		12	
Cable	06																	
Choke Body	08															1		
Coil	10																	
Coupling	12										1							
Diaphragm	15																	
Disc-Regulators	16																	
Ells	17																	
Fasteners	18																	
Fittings	19												1	2				
Flange	20																	
Float	21																	
Foundation	24																	
Gasket	25																	
Gauge	27																	
Gland-Packing	28														1			
Glass-Sight	29							1										
Header	30							1										
Heater	31						1											
Hose	34						1						3					
Joint-Blast	35																	
Liner	39												1				2	
Meters	40																	
Nipple	41													2	3			
O-Ring	43																	
Packers	44																	1
Pig	45																	
Pipe	46								1	1			3		1			1
Piston	47																	
Plug-Bull	48																	
Pump	49						3							1				
Recorders	50																	
Regulator Pressure	52																	
Relay-Electrical	53																	
Riser	55																	
Rods	56																	
Rod-Polished	57																3	
Seals	59																	
Seam	60																	
Sensor Hi-Level	61																	
Sensor Hi-Pressure	63																	
Swage	65												1		1			
Switch	66												1					
Tank Shell	67																	
Tee	68												1					
Thread	69																	
Tubing-Instrument	71																	
Union	72												1					
Union Flange	73																	
Valve	74						5				1		8	4	7			
Valve-Back Pressure	75						1											
Valve-Body	78													1				
Valve-Bypass	79																	
Valve-Check	80												1	1				
Valve-Control	81																	
Valve-Dump	82													1				
Valve-Gate	83																	
Valve-Plug	85						1											
Valve-Pressure Relief	86						1								1			
Vessel-Pressure	88																	
Welds	89																	
Motor	91						1											
Fire Tube	92																	
Control	93																	
Vent	94																	
Tank-Test	95						2						1					
Oil/Line	96																	
Water Line/Line	97																	
Fuel Line/Supply	98																	
Strainer	99																	
TOTALS		1	2	1	1	5	25	6	3	3	4	1	37	17	18	2	17	2

A

Table D-14. Texas Railroad Commission Oil and Gas Division

PRODUCTION SYSTEM																																																	
WELL HEAD SUBSYSTEM	CASING HEAD EQUIPMENT	TUBING HEAD EQUIPMENT	CHOKE FIXED	ROD PUMP	HYDRAULIC LIFT	GAS LIFT	POWER	GATHERING SUBSYSTEM	FLOWLINE EQUIPMENT	CHOKE, FIXED	MANIFOLD EQUIPMENT	METERING EQUIPMENT	PUMPS	AUTOMATIC CONTROL EQUIPMENT	SEPARATOR SUBSYSTEM	SEPARATOR HI-PRESSURE	HI-PRESSURE SEPARATOR CONTROL	SEPARATOR LO-PRESSURE	LO-PRESSURE SEPARATOR CONTROL	SCRUBBER	TREATER SUBSYSTEM	HEATER TREATER EQUIPMENT	HEATER TREATER CONTROL	CHEM-ELECT TREATER CONTROL	CHEM-ELECT TREATER CONTROL	GUN BARREL	SKIMMER	RECIPROCATING PUMP	POWER	STORAGE SUBSYSTEM	TANKS	TANK EQUIPMENT	SUMP EQUIPMENT	FIREWALL	POWER EQUIPMENT	CUSTODY TRANSFER SUBSYSTEM	PUMPS	PUMP CONTROLS	METERING EQUIPMENT	MANIFOLD EQUIPMENT	SAMPLING EQUIPMENT	POWER TANK	POWER	SENSING/DETECTING EQUIPMENT	MONITOR & ALARM EQUIPMENT	WATER DISPOSAL SUBSYSTEM	POWER	PRODUCTION SYSTEM TOTALS	BANK TOTALS
5	2		1			2		1	10		1		15		4		1	12		1	6	47	4			15	1	4	2	8	183	9			2	17	3	3	2	2		4	6		1	3	2	388	711
															1																																1	1
10	3	4		12				1	8				1																		1																	41	41
																															1													1		2	2
			1																																											1	1
																					1																									1	1
									16					1										1						3																24	51
																1																					1									2	2
														3			9			1	1																									14	15
							1	5		1																																				7	7
																								1					1								1									3	5
1	2							8		4										2								1																	18	38
												1																	2																3	16
																												1																	1	2
																				1								14																	15	18
								3				1																								1									5	32
												2																1	1																4	4
		1						1				3																																	5	17
																	3				3																								7	7
								3		2																																			6	10
																				3																									4	4
3											1	2								1																1									9	11
																																													0	1
1				2																																									3	3
											2							1																		5									8	10
		2	3						6	1		1	1																	8				1										1		24	45
									1																																				1	2
				1																																									1	2
																																											1		1	1
3		1			1				724	1	2		4		2	1		2			1	18				7		2			2	51				2									6		829	3314
												1																			1														2	2
								1				1																			2														5	12
	1																	1		1						1			1	11							1							6	2	28	33
																						1																							1	1
																	1			2																									3	3
																																											1		1	1
										1																			1																2	6
																																													0	2
				3																																									3	3
																													1																1	5
																																													0	1
														1			1								1				3	1						2			1			1					11	11
												1																																	1	1
1		1							1																1					1																6	7
1							1						1																1	11	1				1									2	1	20	20
																				1	2								26	1														2	1	33	36
1									2																																				3	8
									3																																				3	7
																																													0	4
1									6																																				7	8
																																													0	1
6	4	7						1	25	1	2				4			2	1		1	7	4	2		4		2		1	19	52		2		3	2		1	1				1		4	1	168	208
									1					1		1		3	1		1	2		1	1																							13	13
	1																										1																			2	2
																									1						1															2	6
1	1								13																					4																19	84
									1					1								1			1					1	2																7	8
	1								1					14	1	1	4	11		1	24	20		2	1		1																			84	84
									3												1				1																					5	32
																																													1	1
		1								1							1			1	1			1			1								1			1									10	12
																					2																								2	3
									1																																				1	10
												2																	1	3					1											8	11
																				14													2													16	16
												1		1											1				1	5				1		1								2	1	14	17
														1			2											1																		4	4
1														1																																4	4
																					2				4	1	2																			9	9
																				5	3				6						1															15	15
														1																																1	1
																																													0	10
37	17	18	2	17	2	2	1	4	845	3	14	4	36	2	26	3	3	40	14	2	18	137	30	3	4	46	2	14	2	10	257	173	4	2	4	36	7	6	14	3	1	4	6	2	1	28	8	1853	6094

Table D-15. Alberta, Canada - Alberta Oil and Gas Conservation Board

Element		GATHERING/DISTRIBUTION SYSTEM								DRILLING SYSTEM						PRODUCTION SYSTEM																
Component	Code	10000 Gathering/ Distribution System	11000 Pipeline Subsystem	11100 Pipe	11200 Scraper Trap Equipment	13000 Pump Station Subsystem	13100 Pumps	15000 Gathering Pipeline Subsystem	Gathering/Distribution System Totals	20000 Drilling System	21000 Well Subsystem	24000 Mud Subsystem	25000 Drill String Subsystem	25400 Drill Pipe	Drilling System Totals	30000 Production System	31000 Well Subsystem	32000 Well Head Subsystem	32100 Casing Head Equipment	32500 Rod Pump	32900 Power	33000 Gathering Subsystem	33100 Flow Line Equipment	33600 Pumps	35000 Treater Subsystem	35100 Heater Treater	36000 Local Storage Subsystem	36100 Tanks	36200 Tank Associated Equipment	36300 Sump System	Production System Totals	Bank Totals
Not Identified	00			1	1	1	1		4		1	3		1	5	58	3		1	2	2		1	2		6		22	1	3	101	110
Box Stuffing	05																			13											13	13
Ells	17																											1			1	1
Gasket	25																	1													1	1
Gland . Packing	29																			1											1	1
Hose	34					1			1																	2					2	3
Nipple	41																	1					2								3	3
Pipe	48			4				1	5														52	1		1		1			55	60
Regulator . Pressure	52															1															1	1
Rods	56																			1											1	1
Rod . Polished	57																			4											4	4
Union	72			1					1																							1
Valve	74															1		1	1	3				1		25		3			35	35
Valve . Dump	82																									1					1	1
TOTALS				6	1	2	1	1	11		1	3		1	5	60	3	3	2	24	2		55	4		35		27	1	3	219	235

SYSTEM ELEMENT / COMPONENT	CODE	GATHERING/DISTRIBUTION SYSTEM										DRILLING SYSTEM																		
		11000 PIPELINE SUBSYSTEM	11100 PIPE	11200 SCRAPER TRAP EQUIPMENT	11900 SUBMERGED CROSSING LAND	12100 TANK	12300 TANK ASSOCIATED EQUIPMENT	13100 PUMP	13400 MANIFOLD	15000 GATHERING PIPELINE SUBSYSTEM	GATHERING/DISTRIBUTION SYSTEM TOTALS	20000 DRILLING SYSTEM	21000 WELL SUBSYSTEM	25600	26300 ANNULAR (BAG TYPE) BOP	DRILLING SYSTEM TOTALS	30000 PRODUCTION SYSTEM	31000 WELL SUBSYSTEM	31200 CASING STRING	31300 PRODUCTION TUBING	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32300 CHOKE, FIXED	33000 GATHERING SUBSYSTEM	33100 FLOW LINE EQUIPMENT	33400 MANIFOLD	33600 PUMPS	34000 SEPARATION SUBSYSTEM	34100 SEPARATORS,
Not Identified	00	5	1			1		1			8	2	2	1	1	6	13	4		1	2	1		3		18		3	7	
Bell, Alarm	01																													
Blowcase, Saltwater	03																1													
Choke Body	08																				1			5		1				
Choke Target	09																							1						
Coupling	12																											2		
Diaphragm	15																										1			
Disc, Rupture	16																1												2	
Ells	17																									1				1
Fasteners	18																									1				
Flange	20																									3		1		
Float	21																													
Gasket	25								1		1						1											2		
Gauges	27			1							1															1				
Gland, Packing	28																						1					2		
Glass, Sight	29																													
Heater	30																1										1			
Hose	34																									3	1			
Meters	40																1													
Nipple	41																												1	
O-Rings	43			1							1														1					
Packers	44																		1											
Pig	45			2							2																			
Pipe	46		1	1				1		1	4						2				2					26	1	4	1	
Plug, Bull	48																				1					1				
Pump	49	5	1								6						2											3		
Riser	55																									1				
Seals	59																											2		
Sensor, Level, High	61																											3		
Sensor, Level, Low	62																													
Sensor, Pressure, High	63																				3									
Sensor, Pressure, Low	64																													
Switches	66																											2		
Tank Shell	67																													
Tees	68																				1									1
Tubing Hanger	70																			1										
Valve	74						1				1						3				1					4	1	1		
Valve, Back Pressure	75																1												1	
Valve, Ball	76																													
Valve, Body	78																				1					1				
Valve, Check, Reverse Flow	80	2									2						1					1						1		
Valve, Control	81																				1									
Valve, Dump	82																												9	1
Valve, Needle	84																1			1										1
Valve, Relief, Pressure	86																1					1	1						1	
Valve, Trim	87																													
Vessel, Pressure	88																													
Fire-Tube	92				1						1																			
Controls	93																1												1	
Test Tank	95																				1									
Water Line/Leg	97																												1	
TOTALS		12	3	5	1	1	1	2	1	1	27	2	2	1	1	6	30	4	1	3	14	3	2	9	1	61	5	26	24	7

A

Table D-16. Component Versus System Element for Moderate Spills Offshore

PRODUCTION SYSTEM

33100 FLOW LINE EQUIPMENT	33400 MANIFOLD	33600 PUMPS	34000 SEPARATION SUBSYSTEM	34100 SEPARATORS, HIGH PRESSURE	34200 SEPARATORS, HIGH CONTROLS	34300 SEPARATORS, LOW PRESSURE	34400 SEPARATORS, LOW CONTROLS	34500 SCRUBBER	34600 SCRUBBER CONTROLS	35000 TREATER SUBSYSTEM	35100 HEATER TREATER	35200 HEATER TREATER CONTROLS	35300 CHEMICAL–ELECTRICAL TREATER	35500 GUN BARREL	35600 SKIMMER (SETTLING)	35700 FREE–WATER KNOCKOUT	36000 LOCAL STORAGE SUBSYSTEM	36100 TANKS	36200 TANK ASSOCIATED EQUIPMENT	36300 SUMP SYSTEM	37000 CUSTODY TRANSFER SUBSYSTEM	37100 PUMPS	37200 PUMP CONTROLS	37700 POWER	38000 SAFETY SHUTDOWN & ALARM SUBSYSTEM	38100 ENERGY SOURCE	38200 ENERGY SOURCE DISTRIBUTION EQUIPMENT	38300 SENSING OR DETECTING EQUIPMENT	38400 MONITORING AND ALARM PANELS	38500 SUBSURFACE SAFETY VALVE	38600 HIGH/LOW PRESSURE VALVE	38900 WATER DISPOSAL OR INJECTION SUBSYSTEM	PRODUCTION SYSTEM TOTALS	ALL SYSTEMS TOTALS
18		3	7	1		10	1	1		3	3	1	1	1	5	3		11	1	12	1	2	1	1	5	1	1			1	1	2	122	136
																			1									1	1				3	3
																																	1	1
1																																	7	7
																																	1	1
		2															1																3	3
	1																																1	1
			2			7				1	1		1			1		1															15	15
1				1																													2	2
1																																	1	1
3		1				1																											5	5
							1								1																		2	2
		2									1										1												5	6
1																					1												2	3
		2																															3	3
															1																		1	1
	1																																2	2
3	1																		1														5	5
																																	1	1
			1																	1													2	2
																																	1	2
																																	1	1
																																		2
26	1	4	1								2		1		2				2	2													45	49
1																																	2	2
		3													1	1			5	9												1	22	28
1																																	1	1
		2																															2	2
		3			1	5	4	2	2		5			2	1	1		2	7	6					4							1	46	46
																			1						1								2	2
																1																	4	4
															1																		1	1
		2																															2	2
																				1													1	1
				1																													2	2
																																	1	1
4	1	1				1		1			1								3	1					4								21	22
			1			1																											3	3
											1																						1	1
1						1																											3	3
		1				1													1	2	1												8	10
														1																			2	2
			9	3	3	9	4	2		2	7	1	2	3	3																		48	48
				1																													3	3
			1			4										2																	10	10
						1																											1	1
						1								1																			2	2
											1																						1	2
			1				2												1	2					1								8	8
																																	1	1
			1																														1	1
	5	26	24	7	4	42	12	6	2	6	22	2	5	8	15	9	1	14	23	36	4	2	1	1	15	1	1	1	1	1	1	4	430	463

B

SYSTEM ELEMENT / COMPONENT	CODE	GATHERING/DISTRIBUTION SYSTEM																			DRILLING SYSTEM								
		10000 GATHERING/ DISTRIBUTION SYSTEM	11000 PIPELINE SUBSYSTEM	11100 PIPE	11200 SCRAPER TRAP EQUIPMENT	11500 SUBMERGED CROSSING LAND	12100 TANK	12300 TANK ASSOCIATED EQUIPMENT	13200 METERING EQUIPMENT	13000 VALVE	13500 VALVE OPERATING EQUIPMENT CONTROLS	13400 DRAINAGE SYSTEM	13000 PUMP SUBSYSTEM	13100 PUMP	14300 FLOW AND GAUGE INDICATING EQUIPMENT	15000 GATHERING PIPELINES SUBSYSTEM	15100 GRAVITY	15200 SUCTION	15300 PRESSURE	GATHERING/DISTRIBUTION SYSTEM TOTALS	21100 HOLE	26300 KELLY	26800 ANNULAR (BAG TYPE) BOP	26400 DOWNHOLE BOP	DRILLING SYSTEM TOTALS	30000 PRODUCTION SYSTEM	31000 WELL SUBSYSTEM	31400 DOWNHOLE ASSEMBLY	WELL HEAD
Not Identified	00			39	1		21			2	1		3	2	1					70		1	1	1	3	8	1	1	
Blowcase, Saltwater	03																												
Choke Body	06																				1				1				
Coupling	12			6									1				1			8									
Disc, Rupture	16																												
Fittings	19			11									1			2				14									
Flange	20			4										1						5									
Foundation	24			1			1													2									
Gasket	25			1							1			1						3									
Gauges	27																												
Gland, Packing	28													3						3									
Hose	34						1						1							2									
Meters	40						2	2	1											5									
Nipple	41			2										1						3									
Pipe	46	1		513		16		1					3	1		62	8	2	2	609									
Plug, Bull	48			4															1	5									
Pump	49																												
Riser	55			1																1									
Seals	59				1															1									
Seam	60			2																2									
Sensor, Level, High	61																												
Switches	66			1																1									
Tank Shell	67						2													2									
Tees	68															1				1									
Threads	69			2										1						3									
Tubing, Instrument	71													1						1									
Valve	74	1	2	9			3	2		1			1			1				20						3			1
Valve, Check, Reverse Flow	80			1												1				2									
Valve, Control	81																												
Valve, Dump	82																												
Valve, Gate	83			3						1										4									
Valve, Relief, Pressure	86			1			1													2									
Welds	89			13									2			2				17									
Motor	91						1							1						2						1			
Fire–Tube	92																												
Controls	93							1				1		1						3									
Vent	94																												
Oil Leg	96																												
Water Line/Leg	97																												
Strainer	99								1				1	3						5									
TOTALS		2	2	614	2	16	32	6	2	4	2	1	13	16	1	69	9	2	3	796	1	1	1	1	4	12	1	1	1

A

Table D-17. Component Versus System Elements, Major Spills Onshore

PRODUCTION SYSTEM																																
31000 WELL SUBSYSTEM	31400 DOWNHOLE ASSEMBLY	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32900 POWER	33100 FLOW LINE EQUIPMENT	33400 MANIFOLD	33500 METERING	33600 PUMPS	34000 SEPARATION SUBSYSTEM	34200 SEPARATORS, HIGH CONTROLS	34300 SEPARATORS, LOW PRESSURE	34400 SEPARATORS, LOW CONTROLS	35000 TREATER SUBSYSTEM	35100 HEATER TREATER	35200 HEATER TREATER CONTROLS	35300 CHEMICAL–ELECTRICAL TREATER	35500 GUN BARREL	35600 SKIMMER (SETTLING)	35700 FREE–WATER KNOCKOUT	36000 LOCAL STORAGE SUBSYSTEM	36100 TANKS	36200 TANK ASSOCIATED EQUIPMENT	36300 SUMP SYSTEM	36500 POWER	37000 CUSTODY TRANSFER SUBSYSTEM	37100 PUMPS	37300 METERING EQUIPMENT	37400 MONITORING AND ALARM PANELS	38000 WATER DISPOSAL OR INJECTION SUBSYSTEM	PRODUCTION SYSTEM TOTALS	ALL SYSTEMS TOTALS
1	1				1	1						3		2	9			1			2	38		1	1	2	1		1		73	146
										1																					1	1
																																1
																																8
											1	1																			2	2
																																14
																																5
																						4									4	6
									1																						1	4
																						1									1	1
																																3
								1							1																2	4
								1																				1			2	7
																																3
				1		34				1								2		1		2	3	1						1	46	655
			1																												1	6
																							1	1							2	2
																																1
																																1
																																2
																							1								1	1
																							1	1						1	3	4
																						7									7	9
																																1
																																3
																																1
		1				2	2						1		4		2			1		7	10							1	34	54
						1																	1								2	4
																		1													1	1
										1		1	1	1	6	1			1												12	12
																																4
																																2
						1																									1	18
																															1	3
															1																1	1
																		1					1			1				2	5	8
																							1								1	1
																		1													1	1
																		2													2	2
																																5
1	1	1	1	1	1	39	2	2	1	3	1	5	2	3	21	1	2	8	1	2	2	59	19	4	1	3	1	1	1	5	207	1007

B

Table D-18. Component Versus Cause, Gathering/Distribution Systems, All Spills

COMPONENT / CAUSE	CODE	UNKNOWN	NO MALFUNCTION	NOT REPORTED	EQUIPMENT FAILURE	BROKEN	BURST/RUPTURED	CORRODED	CORRODED EXTERNALLY	CORRODED INTERNALLY	DEFECT, MATERIAL	FAILURE, OPENED	FROZE & BURST	HOLE	LEAKING	NON-FUNCTIONING	OVERFLOWED	OVER-PRESSURE	PARTED, LINE OR UNION	PLUGGED	WELD DEFECTIVE	DEACTIVATED OR REMOVED	OPERATION INCORRECT	TEMPERATURE	THIRD PARTY	COLLISION	FARM MACHINERY	FOREIGN OBJECT	ROAD MACHINERY	VANDALISM	TOTALS
		1	2	3	10	12	14	15	16	17	20	22	24	25	26	30	31	32	33	34	39	44	51	79	90	92	93	94	96	99	
Not Identified	00	14		14	9	15	13	27	82	23	1			7	119	7	9	8	3			1	5	2		4	4		19	5	391
Coupling	12				2	1	1	1			3				12				11	1									1		33
Disc, Rupture	16					1																									1
Fasteners	18					3																									3
Fittings	19				1	3		1		1	2				9				8		1			2			1		1		30
Flange	20					4	2								6				2									1	1		16
Float	21															1															1
Foundation	24				1						1																				2
Gasket	25				1	1	25	2							8	1					1										39
Gasket Ring	26										1																				1
Gauge	27						1																								1
Gland, Packing	28				2	3	2								6				3												16
Header	30			1		1		1	1																						4
Hose	34			1			1								1								1								4
Joint, Blast	36						1																								1
Meters	40				1					1						1															3
Nipple	41					14		1		1					1				1					1					1		20
O-Ring	43																		1												1
Packers	44			1																											1
Pig	45																														0
Pipe	46	7	20	127	11	19	141	639	1383	336			36	48	240		1	11	32	16	40	10	7	13	41	8	43	9	216	4	3456
Plug, Bull	48	1				1	1		1						2														4		10
Pump	49				3	2	1								4	7	1						3								21
Recorders	52				1																										1
Riser	55									1					1												2		2		6
Rods	56			1			1																								2
Seals	59						4				1				2																7
Seam	60						2								1																3
Swage	65					1		1																							2
Switches	66															1															1
Tank Shell	67						1			1				1	1											1					5
Tees	68					2	1												2	1											6
Threads	69					4	1			1									2												8
Tubing, Instrument	71					1	1		1																						3
Union	72					1									1																2
Union, Flange	73					1																									1
Valve	74	1	3		2	3	6		3		2	5	1	1	10	8	1	1				1	2			1			1	3	55
Valve, Bypass	79						1			1		1																			3
Valve, Check, Reverse Flow	80			1	2	1						31			8	13	2			1						1	1	1	3		65
Valve, Control	81														1																1
Valve, Gate	83		2	1	2	2	4								6				2					2				1	5		27
Valve, Relief, pressure	86											2				1												1			4
Vessel, Pressure	88						1																								1
Welds	89					4	6	1			3				2				1		9										26
Motor	91																														0
Control	93				1											2		1													4
Strainer	99						1													9				1							11
TOTALS		23	25	147	39	88	219	674	1471	366	14	39	37	55	441	42	14	21	88	28	51	12	18	21	41	15	51	13	254	12	4299

Table D-19. Component Versus Cause, Drilling Systems, All Spills

Cause / Component	Code	Unknown	No Malfunction	Not Reported	Well Blew	Burst/Ruptured	Failure Closed	Overflowed	Over Pressure	Parted, Line or Union	Plugged	Seized/Jammed	Operator/Maintenance Error	Left Open	Operation Incorrect	Over Pressure	Design Error	Fire	Well Kicked	Well Flowed	TOTALS
		1	2	3	4	14	23	31	32	33	34	37	40	48	51	53	61	72	82	83	
Not Identified	00	2	1	3	4	1	1	2	1	1		1	2	1	1	1		2	5		29
Choke Body	8																	1			1
Disc, Rupture	16					1															1
Pipe	46									1	1				1		1			1	5
Control	93																1				1
TOTALS		2	1	3	4	2	1	2	1	2	1	1	2	1	2	1	2	3	5	1	37

CAUSE COMPONENT	CODE	UNKNOWN 1	NO MALFUNCTION 2	NOT REPORTED 3	WELL BLEW 4	EQUIPMENT FAILURE 10	BINDING 11	BROKEN 12	BURNED 13	BURST/RUPTURED 14	CORRODED 15	CORRODED EXTERNALLY 16	CORRODED INTERNALLY 17	CUT, FLOW 18	CUT, SAND 19	DEFECT MATERIAL 20	ELECTRICAL MALFUNCTION 21	FAILURE, OPENED 22	FAILURE, CLOSED 23	FROZE AND BURST 24	HOLE 25	LEAKING 26	LOST INSTRUMENT GAS 27	MANUFACTURE OBJECT 28	MISSING HARDWARE 29	NON-FUNCTIONING 30	OVERFLOWED 31	OVER PRESSURE 32	PARTED, LINE OR UNION 33	PLUGGED 34	POWER LOSS, ELECTRICAL 35	SANDED UP 36	SEIZED/JAMMED 37	VIBRATION 38	WELD DEFECTIVE 39	WORN A1	OPER/MAINT. ERROR 40	ADJ./ALIGN. IMPROPER 41	APPLICATION WRONG 42	ASSEMBLED IMPROPERLY 43	DEACTIVATED OR REMOVED 44	HANDLING DAMAGE 45	INSTALLATION IMPROPER 46	LEFT CLOSED 47
Not Identified	00	105	6	95	1	80		28	2	28	13	1	2	3	17		9	1		1	75	161	11			80	195	14	7	11	11	4					32		1	1	9	1	2	
Bell, Alarm	01	1				3																					3											1						
Blowcase, Saltwater	03																	2	2			1				2	1						1					1						
Box, Stuffing	05			3		13		1		8				1						1		30						9	1	4						3								
Cable	06							1									1																											
Choke Bean	07													1																		1												
Choke Body	08												1	16																1														
Choke Target	09														4																													
Coil	10						1																																				
Coupling	12						3		3	1	1		1						1		10							7											2		1		
Detector, Heat	14						1																																			
Diaphragm	15								3																																		
Disc, Rupture	16								53	1							1								1		1								1			2					
Ells	17								2	3			1	4					1		1							2															
Fasteners	18						2		1	1											1																						
Fittings	19	1				1		2		1	4			2						1		9							2															
Flange	20		1					1													1	14												1							1				
Float	21					1											1								3							1												
Float (Oil, Water)	23																									1																	
Foundation	24			1								1									10	2																						
Gasket	25								11	1											4						1																
Gauges	27						4		2												1				1															1			
Gland, Packing	28				1		1		4				1	2							5			1												1							
Glass, Sight	29						7														1																						
Header	30						1			1	1			5						1																1							
Heater	31				1				1												5				1	2																	
Hose	34			1		2		6		17												1						1		1														
Liner	36						1		1										1		1																						
Meters	40				3		1									1								2	1			1		1												
Nipple	41				1		14		3	2	1			2						2	8						1	2															
O-Rings	43								2				2				1				1																						
Packers	44	1				1												1			2																						
Pig	45																				1								1														
Pipe	46	3	2	24		13		124		72	70	62	25	5	5				1	17	116	413		1	2	1	1	6	40	47		3		2	2		5	1			3			
Piston	47						1		1																																	
Plug, Bull	48					1	1		2	1			1	4							3			1																			
Pump	49		2			18		2		5				1			2	1				9	1		1	30	3			3	6	1	1			1					2			
Regulator, Pressure	52	1				1																			2																		
Relay, Electric	53															1																											
Riser	55												1							2	4							1												1			
Rods	56			1				4																																			
Rod Polished	57				4	1	2														1																						
Screen	58																											1															
Seals	59								1												2																						
Seam	60																				1																						
Sensor, Level High	61	1	1			3											3	2	2	1					2	58	4			1	1	3						3			3			
Sensor, Level, Low	62																								6						1												
Sensor, Pressure, High	63															1	1							3	5																		
Sensor, Pressure Low	64																								1	1																	
Swage	65													1						2	1																						
Switches	66				3											8									7	2			1	1													2
Tank Shell	67				1			1	6	5										18	9					3																	
Tees	68								1					2			1			1	2					1																	
Threads	69						1			1																	1															
Tubing Hanger	70																				1																						
Union	72																				10		1					3															
Valve	74	1		6		33	2	10		2				9	5		1	19	10	5	1	23	2			16	4	5	1	3			2	1			2	9			1	1	1	25
Valve, Back Pressure	75				3		1										9	1							2												1						
Valve, Ball	76													1							1																						
Valve, Body	78								1				3	2	2																												
Valve, Bypass	79																1	2																									
Valve, Check, Reverse Flow	80				2		2		4	1			1				5	2	3		7				1		3		1											2		1	
Valve, Control	81				1								1				4	1							1	1																	
Valve, Dump	82			1		25		4		4				6	13			51	66	3		3			1	28	2			2			3					1			1		1	
Valve, Gate	83						1														1								1														
Valve, Needle	84						1						1				1																					1				
Valve, Plug	85																																										
Valve, Relief, Pressure	86				5		1										9	4			1	1			4	16	6													1			
Valve, Trim	87													3				1																								
Vessel, Pressure	88										1	1									1					1								1									
Welds	89								1																																		
Motor	91							1								3									3	2				2													
Fire Tube	92						1		1		1									9	3				1																		
Control	93	1				6											4	2					1	2		12	1				2		1					1		1				
Vent	94				1																1					1	3																
Tank, Test	95				1													1	1	1	1					2	1																
Oil Leg	96																				4					1		1	2														
Water Line/Leg	97				2													1			4					1			6		3	1											1
Fuel Line/Supply	98																				1																						
Strainer	99																												1														
TOTALS		115	12	132	1	226	5	233	4	241	106	68	28	41	87	1	33	113	94	36	239	766	16	4	11	268	250	51	68	88	23	18	9	4	3	5	41	18	3	6	24	3	5	28

A

Table D-20. Component Versus Cause of Spill for the Production System

SEIZED/JAMMED 37	VIBRATION 38	WELD DEFECTIVE 39	WORN A1	OPER/MAINT. ERROR 40	ADJ./ALIGN. IMPROPER 41	APPLICATION WRONG 42	ASSEMBLED IMPROPERLY 43	DEACTIVATED OR REMOVED 44	HANDLING DAMAGE 45	INSTALLATION IMPROPER 46	LEFT CLOSED 47	LEFT OPEN 48	LUBRICATION IMPROPER 49	MAINTENANCE IMPROPER 50	OPERATION INCORRECT 51	PRESSURE, DEFICIENT 52	PRESSURE, OVER 53	SAFETY VIOLATION 54	TOOLS FAULTY OR IMPROPER 56	ENGINEERING ERROR 60	DESIGN 61	APPLICATION 62	LAYOUT 63	UNSTABLE ADJUSTMENT 64	NATURAL CAUSES 70	EARTHQUAKE 71	FIRE 72	FLOOD 73	RAIN 74	ICE FLOES 75	LANDSLIDE 76	LIGHTNING 77	MARINE GROWTH 78	TEMPERATURE 79	ICE AND SNOW 80	WIND, HIGH 81	WELL KICKED 82	WELL FLOWED 83	THIRD PARTY 90	BOAT 91	COLLISION 92	FARM MACHINERY 93	FOREIGN OBJECT 94	LIVESTOCK 95	ROAD MACHINERY 96	UNKNOWN 97	VALVE OPENED OR CLOSED 98	VANDALISM 99	TOTALS
				32		1	1	9	1	2		2		31	41	1	1	2			3		2		3		8	6	13			36				13		28	6	5	2			1	1	1		10	1223
					1																																												8
1					1																																												10
			3											11	2																													1					88
																																																	2
																																																	2
																																																	18
																																																	4
																																																	1
							2		1																						1			3							1				1				36
																																																	1
																																																	4
			1			2															1																	1											62
																																																	14
																																							1										6
															1																																	1	25
	1						1																																										19
																																																	6
																																																	1
																																1																	15
																																																	17
								1																																									9
				1																																													16
																																											1						9
				1																																													10
																1											1																						12
																																																	28
																																																	4
																																																	10
																																																	36
																																																	6
																																																	5
																																																	2
	2	2		5	1			3							5						1	2						5	3					9		6			4		9	6	7		11			1	1135
																																																	2
																																						1											15
1			1					2				2			1	1													1			1		1															96
																																		2	1														7
																																																	1
								1																												1													10
																																																	5
																																																	8
																																																	1
																																																	3
																																																	1
					3			3						2				2																															92
																																																	7
																																																	10
																																																	2
																																																	4
											2				1																													1					26
																													3			2												1					49
																																																	8
																																																	3
																																																	1
																																																	14
2	1			2	9			1	1	1	25	33		2	11			1																2			1		3					13	4	1	15	14	300
					1																													1															18
																																																	2
																																																	6
												1																																					4
								2		1																																						1	36
																																														1			10
3					1			1		1				2	2																			2									1				1		222
																																												1				1	5
							1																																										4
												1																																					1
								1															2																										50
																																																	4
		1																																															5
																																																	1
																																1		1															13
																																																	16
1					1		1																																										34
															4																																		10
															1																																		9
																						1							1			1																	11
1											1														1																								20
																																																	1
																																																	1
9	4	3	5	41	18	3	6	24	3	5	28	39	0	48	69	3	1	5	0	0	5	3	4	0	4	0	9	11	21	0	1	42	0	21	1	20	1	30	14	5	12	6	9	18	17	3	16	28	3993

B

CAUSE / COMPONENT		WORN	UNKNOWN	NO MALFUNCTION	NOT REPORTED	EQUIPMENT FAILURE	BROKEN	BURST/ RUPTURED/SPLIT	CORRODED	CORRODED, EXTERNALLY	CORRODED, INTERNALLY	DEFECT, MATERIAL	ELECTRICAL MALFUNCTION	FAILURE OPENED	FAILURE CLOSED	HOLE	LEAKING	MANUFACTURER'S DEFECT	MISSING HARDWARE	NON FUNCTIONING	OVERFLOWED	OVERPRESSURE	PARTED, LINE OR UNION	PLUGGED	POWER LOSS ELECTRICAL	VIBRATION
	CODE	A1	01	02	03	10	12	14	15	16	17	20	21	22	23	25	26	28	29	30	31	32	33	34	35	38
Not Identified	00				3		1	5	7	7	9	1			1	3	9			2	3		1		1	
Coupling	12					1						2					1						3			
Fittings	19					1	1				1						1		1				5			1
Flange	20						3	1															1			
Foundation	24					1						1														
Gasket	25							2												1						
Gland, Packing	28						1	1									1									
Hose	34				1																					
Meters	40					1					1		2							1						
Nipple	41						2			1																
Pipe	46	1	3	3	9	1	2	41	67	172	58	25				7	18	2				1	8	2		1
Plug, Bull	48		1					1		1																
Riser	55																									
Seals	59							1																		
Seam	60							2																		
Switches	66																			1						
Tank Shell	67										1					1										
Tees	68						1																			
Threads	69						3																			
Tubing, Instrument	71							1																		
Valve	74	1					1	2				2		1	1					2		1				
Valve, Check, Reverse Flow	80						1							1												
Valve, Gate	83			1				1																		
Valve, Relief, Pressure	86													1						1						
Welds	89						2	1	1			3					1						1			
Motor	91												2													
Controls	93					1														1		1				
Strainer	99																							4		
TOTALS		2	4	4	13	6	18	59	75	181	70	34	4	3	2	11	31	2	1	9	3	3	19	6	1	2

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Table D-21. Component Versus Cause, G/D Onshore, Major Spills

OVERFLOWED	OVERPRESSURE	PARTED, LINE OR UNION	PLUGGED	POWER LOSS ELECTRICAL	VIBRATION	WELD, DEFECTIVE	OPERATOR/MAINTENANCE ERROR	ADJUSTMENT OR ALIGNMENT IMPROPER	DEACTIVATE OR REMOVED (FOR MAINTENANCE, MODIFICATION, OR TEST)	HANDLING DAMAGE	LEFT CLOSED	LEFT OPEN	MAINTENANCE, IMPROPER	OPERATION, INCORRECT	PRESSURE, OVER	LAYOUT	NATURAL CAUSES	EARTHQUAKE	FLOOD	LANDSLIDE	LIGHTNING	TEMPERATURE	WIND, HIGH	THIRD PARTY	BOAT ANCHOR	COLLISION	FARM MACHINERY	FOREIGN OBJECT DAMAGE	LIVE STOCK	ROAD MACHINERY	VANDALISM	TOTALS
31	32	33	34	35	38	39	40	41	44	45	47	48	50	51	53	63	70	71	73	76	77	79	81	90	91	92	93	94	95	96	99	
3		1		1			1	1					1	3							1		2			1	2			2	3	70
		3											1																			8
		5			1	1																2										14
		1																														5
																																2
																																3
																																3
														1																		2
																																5
																																3
	1	8	2		1	19	1		1	1	1	2	1	4	4	1	1	1	5	2	1	4		24	6	1	18	3	1	86		609
																														2		5
																														1		1
																																1
																																2
																																1
																																2
																																1
																																3
																																1
	1							2			5			1																	1	20
																																2
																						1								1		4
																																2
		1				8																										17
																																2
	1																															3
			4																			1										5
3	3	19	6	1	2	28	2	3	1	1	6	2	3	9	4	1	1	1	5	2	2	8	2	24	6	2	20	3	1	92	4	796

B

CAUSE COMPONENT		UNKNOWN	NO MALFUNCTION	NOT REPORTED	BLOWOUT (WELL BLEW)	EQUIPMENT FAILURE	BROKEN	BURST/ RUPTURED/SPLIT	CORRODED	CORRODED, EXTERNALLY	CORRODED, INTERNALLY	CUT, FLOW	CUT, SAND	ELECTRICAL MALFUNCTION	FAILURE OPENED	FAILURE CLOSED	HOLE	LEAKING	MISSING HARDWARE	NON FUNCTIONING	OVERFLOWED	OVERPRESSURE	PARTED, LINE OR UNION	PLUGGED	POWER LOSS, ELECTRICAL	SANDED UP	SEIZED/ JAMMED	OPERATOR/
	CODE	01	02	03	04	10	12	14	15	16	17	18	19	21	22	23	25	26	29	30	31	32	33	34	35	36	37	4
Not Identified	00	4	1	5	1	12		3	2					1			15	5		5	4	1						
Blowcase, Saltwater	03															1												
Disc, Rupture	16							2																				
Foundation	24																2	2										
Gasket	25							1																				
Gauges	27						1																					
Hose	34					2																						
Meters	40						1																			1		
Pipe	46			1			5	7	2	1	1						7	9	1			1	4	2				
Plug, Bull	48																											
Pump	49																			1								
Sensor, Level, High	61																			1								
Switches	66													2														
Tank Shell	67							4									2	1										
Valve	74			1		2	2					1	1		4	1				1		1						1
Valve, Check, Reverse Flow	80						1																					
Valve, Control	81														1													
Valve, Dump	82					2		1							3	2				2							1	
Welds	89							1																				
Motor	91													1														
Fire–Tube	92																1											
Controls	93					1									1					2					1			
Vent	94					1																						
Oil Leg	96																											
Water Line/Leg	97																									1		
TOTALS		4	1	7	1	20	10	19	4	1	1	1	1	4	9	4	27	17	1	12	4	3	4	2	1	2	1	1

A

Table D-22. Component Versus Cause, Production Onshore, Major Spills

OVERFLOWED	OVERPRESSURE	PARTED, LINE OR UNION	PLUGGED	POWER LOSS, ELECTRICAL	SANDED UP	SEIZED/ JAMMED	OPERATOR/ MAINTENANCE ERROR	ADJUSTMENT OR ALIGNMENT, IMPROPER	DEACTIVATED OR REMOVED (FOR MAINTENANCE, MODIFICATION, OR TEST)	LEFT CLOSED	LEFT OPEN	OPERATION, INCORRECT	APPLICATION	LAYOUT	FIRE	FLOOD	RAIN	LIGHTNING	TEMPERATURE	WIND, HIGH	WELL FLOWED	THIRD PARTY	FOREIGN OBJECT DAMAGE	LIVE STOCK	ROAD MACHINERY	VALVE WAS OPENED/CLOSED	VANDALISM	TOTALS
31	32	33	34	35	36	37	40	41	44	47	48	51	62	63	72	73	74	77	79	81	83	90	94	95	96	98	99	
4	1											1		1	2	1	1	3		3		1					1	73
																												1
																												2
																												4
																												1
																												1
																												2
					1																							2
	1	4	2													1				1		2			1			46
																					1							1
											1																	2
																												1
										1																		3
																												7
	1						1	2		2	1	1							1			1		2		5	4	34
									1																			2
																												1
						1																	1					12
																												1
																												1
																												1
				1																								5
																												1
													1															1
					1					1																		2
4	3	4	2	1	2	1	1	2	1	4	2	2	1	1	2	2	1	3	1	4	1	4	1	2	1	5	5	207

B

Table D-23. Component Versus Cause, G/D Offshore, Moderate Spills

CAUSE COMPONENT		EQUIPMENT FAILURE	BROKEN	BURST/ RUPTURED/SPLIT	CUT, SAND	FAILURE OPENED	LEAKING	NON FUNCTIONING	OVERFLOWED	OVERPRESSURE	PARTED LINE OR UNION	SEIZED/ JAMMED	LEFT OPEN	COLLISION	TOTALS
	CODE	10	12	14	19	22	26	30	31	32	33	37	48	92	
Not Identified	00	1					2		1	3	1			1	9
Gasket	25			1											1
Gauges	27			1											1
O-Rings	43				1										1
Pig	45											2			2
Pipe	46			2			1						1		4
Pump	49		1				1	4							6
Valve	74					1									1
Valve, Check, Reverse Flow	80					1	1								2
TOTALS		1	1	4	1	2	5	4	1	3	1	2	1	1	27

CAUSE COMPONENT		WORN	UNKNOWN	NO MALFUNCTION	NOT REPORTED	EQUIPMENT FAILURE	BROKEN	BURST/ RUPTURED/SPLIT	CUT, FLOW	CUT, SAND	ELECTRICAL MALFUNCTION	FAILURE OPENED	FAILURE CLOSED	HOLE	LEAKING	LOST INSTRUMENT GAS	MISSING HARDWARE	NON FUNCTIONING	OVERFLOWED	OVERPRESSURE	PARTED, LINE OR UNION	PLUGGED	POWER LOSS, ELECTRICAL	SANDED UP	SEIZED/ JAMMED	VIBRATION	OPERATOR/MAINTENANCE
	CODE	A1	01	02	03	10	12	14	18	19	21	22	23	25	26	27	29	30	31	32	33	34	35	36	37	38	4
Not Identified	00		9		2	7	4	2	1	10				1	6	1		16	36	3	2	3	1	2			[illegible]
Bell, Alarm	01		1			2																					
Blowcase, Saltwater	03																		1								
Choke Body	08									7																	
Choke Target	09									1																	
Coupling	12						1								2												
Diaphragm	15							1																			
Disc, Rupture	16	1						12										1									
Ells	17									2																	
Fasteners	18																										
Flange	20														4												
Float	21							5										2									
Gasket	25																										
Gauges	27						1								1												
Gland, Packing	28							2																			1
Glass, Sight	29														1												
Header	30									2																	
Hose	34						2	3																			
Meters	40																		1								
Nipple	41						1	1																			
O-Rings	43								1																		
Packers	44		1																								
Pipe	46			1		1	3	4	1	3					17					2	2	4				2	1
Plug, Bull	48							1		1																	
Pump	49					4		2	1		1							11				1					
Riser	55																				1						
Seals	59							1							1												
Sensor, Level, High	61					2							1				1	33	2					1			
Sensor, Level, Low	62																	2									
Sensor, Pressure, High	63																	4									
Sensor, Pressure, Low	64																		1								
Switches	66										1							1									
Tank Shell	67																										
Tees	68											1			1												
Tubing Hanger	70														1												
Valve	74					1			3	3		1	1		3			4									
Valve, Back Pressure	75						1					1						1									
Valve, Ball	76									1																	
Valve, Body	78								1	2																	
Valve, Check, Reverse Flow	80					1									4							1					
Valve, Control	81					1												1									
Valve, Dump	82					4	1		3	5		13	15					6									
Valve, Needle	84						1		1			1															
Valve, Relief, Pressure	86					1						3							4	1							
Valve, Trim	87									1																	
Vessel, Pressure	88														1				1								
Fire-Tube	92																	1									
Controls	93															1		5							1		
Test Tank	95													1													
Water Line/Leg	97						1																				
TOTALS		1	11	1	2	24	16	34	12	38	2	20	17	2	42	2	1	88	46	6	5	9	1	3	1	2	7

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Table D-24. Component Versus Cause for Offshore Production System Moderate Spills

	LOST INSTRUMENT GAS	MISSING HARDWARE	NON FUNCTIONING	OVERFLOWED	OVERPRESSURE	PARTED, LINE OR UNION	PLUGGED	POWER LOSS, ELECTRICAL	SANDED UP	SEIZED/ JAMMED	VIBRATION	OPERATOR/MAINTENANCE ERROR	APPLICATION, WRONG	ASSEMBLED IMPROPERLY	DEACTIVATED OR REMOVED (FOR MAINTENANCE, MODIFICATION, OR TEST)	INSTALLATION, IMPROPER	LEFT CLOSED	LEFT OPEN	MAINTENANCE, IMPROPER	OPERATION, INCORRECT	PRESSURE, DEFICIENT	SAFETY VIOLATION	DESIGN	NATURAL CAUSES	RAIN	WIND, HIGH	THIRD PARTY	BOAT ANCHOR	COLLISION	FOREIGN OBJECT DAMAGE	
	27	29	30	31	32	33	34	35	36	37	38	40	42	43	44	46	47	48	50	51	52	54	61	70	74	81	90	91	92	94	TOTAL
	1		16	36	3	2	3	1	2			5		1					1	3			1	1	2	1		1			122
																															3
				1																											1
																															7
																															1
																															3
																															1
			1										1																		15
																															2
																											1				1
														1																	5
			2																												2
																															5
																															2
												1																			3
																															1
																															2
																															5
				1																											1
																															2
																															1
																															1
7					2	2	4				2	1																	1	3	45
																															2
			11				1								1						1										22
						1																									1
1																															2
		1	33	2					1						2				2			2									46
			2																												2
			4																												4
				1																											1
			1																												2
																									1						1
1																															2
1																															1
3			4												1		1	3													21
			1																												3
																															1
																															3
4							1								1	1															8
			1																												2
			6																1												48
																															3
				4	1										1																10
																															1
1				1																											2
			1																												1
	1		5							1				1																	8
																															1
																															1
42	2	1	88	46	6	5	9	1	3	1	2	7	1	3	6	1	1	3	4	3	1	2	1	1	3	1	1	1	1	3	430

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		GATHERING/DISTRIBUTION SYSTEM																			DRILLING SYSTEM															
ELEMENT / COMP	CODE	10000 TRANSPORTATION SYSTEM	11000 PIPELINE SUBSYSTEM	11100 PIPE	11200 SCRAPER TRAP EQUIPMENT	11400 SUBMERGED CROSSING WATER	11500 SUBMERGED CROSSING LAND	12100 TANK	12200 TANK ASSOCIATED EQUIPMENT	13000 PUMP STATION SUBSYSTEM	13100 PUMP	13200 METERING EQUIPMENT	13300 VALVE	13600 VALVE OPERATING EQUIPMENT CONTROLS	13400 DRAINAGE SYSTEM	15000 GATHERING PIPELINE SUBSYSTEM	15100 GRAVITY	15200 SUCTION	15300 PRESSURE	GATHERING/DISTRIBUTION SYSTEM TOTALS	21100 HOLE	25200 KELLY	26300 ANNULAR (BAG TYPE) BOP	26400 DOWN HOLE BOP	DRILLING SYSTEM TOTALS	30000 PRODUCTION SYSTEM	31000 WELL SUBSYSTEM	31400 DOWNHOLE ASSEMBLY	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32500 POWER	33100 FLOW LINE EQUIPMENT	33400 MANIFOLD	33500 METERING	PUMP
Unknown	01			4																4						4										
No Malfunction	02			3																3								1								
Not Reported	03			11				1		1										13						3							1			
Blowout (Well Blow)	04																						1		1		1									
Equipment Failure	10			2				1				1			1		1			6						1						1			1	
Broken	12			12							3					3				18													6		1	
Burst/Ruptured/Split	14		2	42	1			1		1	4		2			5	1			59											1		5			1
Corroded	15			47			5	1								19	2		1	75													2			
Corroded, Externally	16			162			1	2								15	1			181													1			
Corroded, Internally	17			59				2	1	1						5	1			69													1			
Cut, Flow	18																																	1		
Cut, Sand	19																																	1		
Defect Material	20			30						2			1			1				34																
Electrical Malfunction	21							2	1		1									4						1										
Failure Opened	22			2									1							3						1										
Failure Closed	23							1												1																
Hole	25			6				3										1		10													5			
Leaking	26			21				2		2	2					4				31													8			
Manufacturer's Defect	28			2																2																
Missing Hardware	29			1																1																
Non-Functioning	30			2				2	2		1			2						9																1
Overflowed	31							3												3																
Overpressure	32			2							1									3													1			
Parted Line or Union	33			14												3			1	18													4			
Plugged	34			2							3	1								6													1			
Power Loss Electrical	35							2												2																
Sanded Up	36																																			
Seized/Jammed	37																																			
Vibration	38									1	1									2																
Weld, Defective	39			27						1										28																
Worn	A1			2																2																
Operator/Maintenance Error	40			2																2						1										
Adjustment or Alignment Improper	41	1		1	1															3																
Deactivated or Removed	44															1				1																
Handling Damage	45															1				1																
Left Closed	47			4				2												6																
Left Open	48			1						1										2													1			
Maintenance, Improper	50			2			1													3																
Operation, Incorrect	51	2		2				4	1							1				10																
Pressure, Over	63			4																4																
Application	62																																			
Layout	63			1																1																
Natural Causes	70			1																1																
Earthquake	71			1																1																
Fire	72																				1	1			2											
Flood	73			5																6													1			
Rain	74																																			
Landslide	76			2																2																
Lightning	77			1				1												2																
Temperature	79			5						1						1	1			8																
Wind, High	81							2												2													1			
Well Kicked	82																							1	1											
Well Flowed	83																													1						
Third Party	90			24																24						1							2			
Boat	91			6																6																
Collision	92			1		1				1										3																
Farm Machinery	93			16			1									3				20																
Foreign Object Damage	94			3																3																
Live Stock	95															1				1																
Machinery	96			74			8		1							5	2	1	1	92																
Valve Was Opened/Closed	98																																1			
Vandalism	99			2				1		1										4									1				1			
TOTAL		3	2	614	2	1	16	33	6	13	16	2	4	2	1	68	9	2	3	794	1	1	1	1	4	12	1	1	1	1	1	1	42	2	2	2

A

Table D-25. Cause Versus System Element for Major Spills

	PRODUCTION SYSTEM																																		
DRILLING SYSTEM TOTALS	30000 PRODUCTION SYSTEM	31000 WELL SUBSYSTEM	31400 DOWNHOLE ASSEMBLY	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32900 POWER	33100 FLOW LINE EQUIPMENT	33400 MANIFOLD	33600 METERING	33800 PUMPS	34000 SEPARATION SUBSYSTEM	34200 SEPARATORS, HIGH CONTROLS	34300 SEPARATORS, LOW PRESSURE	34400 SEPARATORS, LOW CONTROLS	35000 TREATER SUBSYSTEM	35100 HEATER TREATER	35200 HEATER TREATER CONTROLS	35300 CHEMICAL-ELECTRICAL TREATER	35400 GUN BARREL	35500 SKIMMER (SETTLING)	35700 PRECIPITATOR	36000 LOCAL STORAGE SUBSYSTEM	36100 TANKS	36200 TANK ASSOCIATED EQUIPMENT	36300 SUMP SYSTEM	36500 POWER	37000 CUSTODY TRANSFER SUBSYSTEM	37100 PUMPS	METERING EQUIPMENT	38000 SAFETY SHUTDOWN & ALARM SUBSYSTEM	38400 MONITORING & ALARM PANELS	39000 WATER DISPOSAL SUBSYSTEM	PRODUCTION SYSTEM TOTALS	ALL SYSTEMS TOTALS
	4																																	4	8
			1																															1	4
	3							1									1							2										7	20
1		1																																1	2
	1						1			1						2	6	1		2			1	1	1			2						19	26
								6		1										1				1	2									11	29
						1		5			1		1	1			1							8									1	19	78
								2									1							1										4	79
								1																										1	182
								1																										1	70
									1																									1	1
									1																									1	1
																																		0	34
	1																								1	1	1							4	8
	1														1		3			1		1											2	9	12
												2					1								1									4	5
								5				1					3							17	1									27	37
								8														1		8										17	46
																																		0	2
																									1									1	2
											1			3			2		1		1				2			1	1		1	1	1	15	24
																								4										4	7
								1									1												1					3	6
								4																										4	22
								1												1					1									3	9
																									1									1	3
																				1										1				2	2
														1																				1	1
																																		0	2
																																		0	28
																																		0	2
	1																																	1	3
																			1						1									2	5
																									1									1	2
																																		0	1
																	1			1				1									1	4	10
								1																	1	1								3	5
																																		0	3
																								1	1									2	12
																																		0	4
																				1														1	1
																							1											1	2
																																		0	1
																																		0	1
2																	1							1										2	4
								1																1										2	7
																										1								1	1
																																		0	2
																								3										3	6
																								1										1	9
								1																4		1								6	8
1																1																		1	2
					1																													1	1
	1							2																1										4	28
																																		0	6
																																		0	3
																																		0	20
															1																			1	4
																									2									2	3
								1																										1	93
				1				1																2	1									5	5
																								3	2									5	9
4	12	1	1	1	1	1	1	42	2	2	2	3	1	3	2	3	21	1	2	8	1	2	2	60	20	4	1	3	2	1	1	1	5	215	1013

B

SYSTEM ELEMENT / CAUSE	CODE	GATHERING/DISTRIBUTION SYSTEM										DRILLING SYSTEM																	
		11000 PIPELINE SUBSYSTEM	11100 PIPE	11200 SCRAPER TRAP EQUIPMENT	11300 SUBMERGED CROSSING LAND	12100 TANK	12200 TANK ASSOCIATED EQUIPMENT	13100 PUMP	13400 MANIFOLD	19000 GATHERING PIPELINES SUBSYSTEM	GATHERING/DISTRIBUTION SYSTEM TOTALS	20000 DRILLING SYSTEM	21000 WELL SUBSYSTEM	29000	29250 ANNULAR (BAG TYPE) BOP	DRILLING SYSTEM TOTALS	30000 PRODUCTION SYSTEM	31000 WELL SUBSYSTEM	31200 CASING STRING	31300 PRODUCTION TUBING	32000 WELL HEAD SUBSYSTEM	32100 CASING HEAD EQUIPMENT	32200 TUBING HEAD EQUIPMENT	32300 CHOKE FIXED	33000 GATHERING SUBSYSTEM	33100 FLOW LINE EQUIPMENT	33400 MANIFOLD	33600 PUMPS	34000 SEPARATION SUBSYSTEM
Worn	A1																												
Unknown	01											1	1			2	2		1										
No Malfunction	02																									1			
Not Reported	03																2												
Blowout (Well Blew)	04											1				1													
Equipment Failure	10							1			1						4												2
Broken	12		1								1						1				1					6		1	2
Burst/Ruptured/Split	14		1	1				1	1		4						3									6	2	7	3
Cut, Flow	18																				2				1	3			
Cut, Sand	19																1				4			9		8	3	1	
Electrical Malfunction	21																1											1	
Failure Opened	22	1					1				2						2			1									2
Failure Closed	23														1	1													8
Hole	25																				1								
Leaking	26	3	1							1	5						2			1	1					22		5	
Lost Instrument Gas	27																												1
Missing Hardware	29																												
Non Functioning	30	4									4						4	1			4					1		4	1
Overflowed	31					1					1			1		1	3	1				1						1	7
Overpressure	32	3									3															3			
Parted, Line or Union	33	1									1															3		1	1
Plugged	34																									1			
Power Loss, Electrical	35																												
Sanded Up	36																												
Seized/Jammed	37			3							3																		
Vibration	38																				1							1	
Operator/Maintenance Error	40												1			1	2	1		1			1						
Application, Wrong	42																												
Assembled, Improperly	43																									1			
Deactivated or Removed (for Maintenance, Modification, or Test)	44																					1	1						
Installation, Improper	46																												
Left Closed	47																												
Left Open	48			1							1						2												
Maintenance, Improper	50																					1							
Operation, Incorrect	51																	1											
Pressure, Deficient	52																											1	
Safety, Violation	54																												
Design	61																1												
Natural Causes	70																												
Rain	74																												
Wind, High	81																												
Third Party	90																									1			
Boat Anchor	91																									1			
Collision	92				1						1															1			
Foreign Object Damage	94																									3			
TOTALS		12	3	5	1	1	1	2	1	1	27	2	2	1	1	6	30	4	1	3	14	3	2	9	1	61	5	23	27

A

Table D-26. Cause Versus System Elements, Offshore Moderate Spills

PRODUCTION SYSTEM																																			
SUBSYSTEM	23100 FLOW LINE EQUIPMENT	23400 MANIFOLD	23500 PUMPS	24000 SEPARATION SUBSYSTEM	24100 SEPARATORS, HIGH PRESSURE	24200 SEPARATORS, HIGH CONTROLS	24300 SEPARATORS, LOW PRESSURE	24400 SEPARATORS, LOW CONTROLS	24600 SCRUBBER	24700 SCRUBBER CONTROLS	25000 TREATER SUBSYSTEM	25100 HEATER TREATER	25200 HEATER TREATER CONTROLS	25300 CHEMICAL—ELECTRICAL TREATER	25400 GUN BARREL	25500 SKIMMER SETTLING	25700 FREE—WATER KNOCKOUT	26000 LOCAL STORAGE SUBSYSTEM	26100 TANKS	26200 TANK ASSOCIATED EQUIPMENT	26300 SUMP SYSTEM	27000 CUSTODY TRANSFER SUBSYSTEM	27100 PUMPS	27200 PUMP CONTROLS	27700 POWER	28000 SAFETY SHUTDOWN & ALARM SUBSYSTEM	28100 ENERGY SOURCE	28200 ENERGY SOURCE DISTRIBUTION EQUIPMENT	28300 SENSING OR DETECTING EQUIPMENT	28400 MONITORING AND ALARM PANELS	28500 SUBSURFACE SAFETY VALVE	28600 HIGH/LOW PRESSURE VALVE	29000 WATER DISPOSAL OR INJECTION SUBSYSTEM	PRODUCTION SYSTEM TOTALS	ALL SYSTEMS TOTALS
											1																							1	1
							2				1					1			1		1									1			1	11	13
	1																																	1	1
																																		2	2
																																			1
				2		1	2	1			1	1	1		1		1			6	1					1			1					24	26
	6		1	2			1											1		1	1	1												16	17
	6	2	7	3			5					3		1			1		1	1		1												34	36
1	3				1	2	1	1													1													12	12
	8	3	1		4		2					2								1	1										1	1		36	36
			1																															2	2
				2	1		4				1	3		2	2	2				1														21	23
				8			2	1	1		1	1	1			1																		16	17
																			1															2	2
	22		5				2					2		1	1	1				1	2	1												42	47
				1				1																										2	2
																					1													1	1
	1		4	1			8	7	4	2		6		1	2	3	4		2	10	11		2	1		7		1					2	88	92
			1	7			11				1	1			1	2	2		7		5				1	2								46	46
	3																1				2													6	9
	3		1	1																														5	6
	1															2					4						1						1	9	9
																						1												1	1
					1		1					1																						3	3
																					1													1	4
			1																															2	2
															1				1															7	8
							1																											1	1
	1																									2								3	3
						1															2					1								6	6
																				1														1	1
									1																									1	1
																				1														3	4
								1				2																						4	4
																1			1															3	3
			1																															1	1
																										2								2	2
																																		1	1
																					1													1	1
																2					1													3	3
																					1													1	1
	1																																	1	1
	1																																	1	1
	1																																	1	2
	3																																	3	3
1	61	5	23	27	7	4	42	12	6	2	6	22	2	5	8	15	9	1	14	23	36	4	2	1	1	15	1	1	1	1	1	1	4	430	463

B

Component / Spill Quantity	Code	GATHERING/DISTRIBUTION SYSTEM																DRILLING SYSTEM															
		0.0 to 1.0 BBLS	1.1 to 2.5 BBLS	Total Minor Spills	2.6 to 10 BBLS	11 to 100 BBLS	101 to 238 BBLS	Total Moderate Spills	239 to 500 BBLS	501 to 1000 BBLS	1001 to 5000 BBLS	5001 to 10,000 BBLS	10,001 or More BBLS	Total Major Spills	Not Reported	Not Determined	Total Spills Gathering/Distribution	0.0 to 1.0 BBLS	1.1 to 2.5 BBLS	Total Minor Spills	2.6 to 10. BBLS	11 to 100 BBLS	101 to 238 BBLS	Total Moderate Spills	239 to 500 BBLS	501 to 1000 BBLS	1001 to 5000 BBLS	5001 to 10,000 BBLS	10,001 or More BBLS	Total Major Spills	Not Reported	Not Determined	Total Spills
		01	02		13	14	15		25	26	27	28	29		41	42		01	02		13	14	15		25	26	27	28	29		41	42	
Not Identified	00	5	3	8	62	205	35	302	35	19	11	1	4	70	29	1	410	3		3	4	4	2	10		1		2		3	12	1	29
Bell, Alarm	01																																
Blowcase, Saltwater	03																																
Box, Stuffing	05																																
Cable	06																																
Choke Bean	07																											1		1			1
Choke Body	08																																
Choke Target	09																																
Coil	10																																
Coupling	12	1	1	2	5	13	8	26	4	4				8			36																
Detector, Heat	14																																
Diaphragm	15																		1	1													1
Disc - Rupture	16					1		1									1																
Ells	17																																
Fasteners	18					1	2	3									3																
Fittings	19				3	10	5	18	9	3	2			14			32																
Flange	20				3	5	3	11	4	1				5			16																
Float	21					1		1									1																
Float (oil-water)	23																																
Foundation	24								2					2			2																
Gasket	25	1	1	2	8	23	6	37	2	1				3			42																
Gasket, Ring	26	1		1													1																
Gauge	27				1			1									1																
Gland, Packing	28				1	7	3	11	1	1	1			3			14																
Glass, Sight	29																																
Header	30				1	3		4									4																
Heater	31																																
Hose	34					2		2	2					2			4																
Joint, Blast	36					1		1									1																
Liner	39																																
Meter	40								2	2		1		5			5																
Nipple	41	1		1	4	10	5	19	1	1			1	3	1		24																
O-Ring	43				1	1		2									2																
Packers	44				1			1									1																
Pig	45	1		1	2			2									3																
Pipe	46	21	26	47	493	1856	438	2787	332	136	124	13	3	608	63	1	3506		2	2											2	1	
Piston	47																																
Plug, Bull	48					6		6	2	3				5			11																
Pump	49	1	3	4	6	7		13							5		22																
Regulator, Pressure	52						1	1									1																
Relay, Electric	53																																
Riser	55		1	1		4		4	1					1			6																
Rod	56					1	1	2									2																
Rod Polished	57																																
Screen	58																																
Seal	59				1	3	2	6		1				1			7																
Seam	60				1			1	1		1			2			3																
Sensor, Hi Level	61																																
Sensor, Lo Level	62																																
Sensor, Hi Pressure	63																																
Sensor, Lo Pressure	64																																
Swage	65					2		2									2																
Switch	66									1				1			1																
Tank Shell	67				1	1	1	3		1	1			2	1		6																
Tee	68				1	5		6									6																
Threads	69				2	1	1	4	2		1			3	1		8																
Tubing Hanger	70																																
Tubing Instrument	71					3		3	1					1			4																
Union	72				1	1		2									2																
Union -Flange	73					1		1									1																
Valve	74	1	2	3	12	31	11	54	12		8			20			77																
Valve -Back Pressure	75																																
Valve - Ball	76																																
Valve - Body	78																																
Valve - By Pass	79				1	3		4									4																
Valve - Check	80				11	51	4	66	1	1				2			68																
Valve - Control	81					1		1									1																
Valve - Dump	82																																
Valve - Gate	83				4	17	7	28	2	1	1			4			32																
Valve - Needle	84																																
Valve - Plug	85																																
Valve - Pressure Relief	86					1	1	2	1		1			2			4																
Valve - Trim	87																																
Vessel- Pressure	88					1		1									1																
Welds	89				1	4	3	8	5	3	7	2		17	1		26																
Motor	91					1		1		1	1			2			3																
Fire Tube	92																																
Control	93					2		2		1	1	1		3			5		1	1													
Vent	94																																
Tank-Test	95																																
Oil/Leg	96																																
Water/Leg	97																																
Fuel Line/Supply	98																																
Strainer	99				1	4	1	6	3		2			5			11																
Totals	--	33	37	70	628	2290	538	3456	425	181	162	18	8	794	101	2	4423	3	4	7	4	4	2	10.		1		3		4	14	2	37

A

Table D-27. Component Versus Quantity Spilled Category by System

	DRILLING SYSTEM																PRODUCTION SYSTEM																
Distribution	0.0 to 1.0 BBLS	1.1 to 2.5 BBLS	Total Minor Spills	2.6 to 10. BBLS	11 to 100 BBLS	101 to 238 BBLS	Total Moderate Spills	239 to 500 BBLS	501 to 1000 BBLS	1001 to 5000 BBLS	5001 to 10,000 BBLS	10,001 or More BBLS	Total Major Spills	Not Reported	Not Determined	Total Spills Drilling System	0.0 to 1.0 BBLS	1.1 to 2.5 BBLS	Total Minor Spills	2.6 to 10. BBLS	11 to 100 BBLS	101 to 238 BBLS	Total Moderate Spills	239 to 500 BBLS	501 to 1000 BBLS	1001 to 5000 BBLS	5001 to 10,000 BBLS	10,001 or More BBLS	Total Major Spills	Not Reported	Not Determined	Total Spills Production System	Total Spills All Systems
	01	02		13	14	15		25	26	27	28	29		41	42		01	02		13	14	15		25	26	27	28	29		41	42		
	3		3	4	4	2	10		1		2		3	12	1	29	109	69	178	201	347	109	657	60	7	8	1	2	78	308	2	1223	1662
																	4		4	1	3		4									8	8
																	3	4	7	2			2	1					1			10	10
																	2	2	4	22	28	1	51							33		88	88
																				1	1		2									2	2
																	1	1	2													2	2
											1		1			1	4	2	6	10	1		11							1		18	19
																	2		2	1	1		2									4	4
																					1		1									1	1
																	4		4	5	22	3	30							2		36	72
																	1		1													1	1
																		1	1	1	2		3									4	4
		1	1													1	7	9	16	21	20	1	42	2					2	2		62	64
																	2	1	3	7	4		11									14	14
																	1		1	1	2	2	5									6	9
																	1	1	2	5	13	1	19							4		35	57
																	8	2	10	4	4	1	9									19	35
																	1	2	3	2	1		3									6	7
																														1		1	1
																				1	7	3	11	4					4			15	17
																		1	1	7	6	1	14	1					1	1		17	89
																																	1
																	1		1	4	2		6		1				1	1		9	10
																	2	1	3	5	6		11							2		16	30
																				3	6		9									9	9
																	2		2	4	4		8									10	14
																	2		2	1	1	2	4							6		12	12
																	7	5	12	4	10	1	15	2					2			29	33
																																	1
																	1		1	2	1		3									4	4
																	1		1	1	5	1	7		1	1			2			10	15
																	3		3	11	18	3	32							1		36	60
																		3	3	2	1		3									6	8
																	1	1	2	1	1		2							1		5	6
																					1		1	1					1			2	5
		2	2											2	1	5	58	37	95	296	546	78	920	31	12	3		1	47	72	1	1135	4646
																		1	1			1	1									2	2
																	3	1	4	5	5		10	1					1			15	26
																	8	14	22	24	28	6	58		1	1			2	14		96	118
																		2	2	5			5									7	8
																					1		1									1	1
																	6	1	7	2	1		3									10	16
																	1		1	1	1	1	3							1		5	7
																		1	1	4	2	1	7									8	8
																		1	1													1	1
																				3			3									3	10
																	1		1													1	4
																	13	17	30	42	16		58		1				1	3		92	92
																	2	3	5	1	1		2									7	7
																				2	4		6							4		10	10
																				1			1							1		2	2
																				1	2	1	4									4	6
																	1	1	2	4	17		21	3					3			26	27
																				3	19	9	31	5	2				7	11		49	55
																	2		2	5	1		6									8	14
																					3		3									3	11
																				1			1									1	1
																																	4
																	4	2	6	1	6		7							1		14	16
																																	1
																	14	10	24	57	129	32	218	27	5	3			35	23		300	377
																		1	1	3	12	1	16							1		18	18
																				1			1							1		2	2
																	1		1	2	2	1	5									6	6
																		1	1	1	1		2							1		4	8
																	4		4	17	9	2	28	2					2	2		36	104
																				1	5	2	8	1					1	1		10	11
																	25	29	54	70	65	15	150	11		1			12	6		222	222
																					2	3	5									5	37
																	1		1		3		3									4	4
																					1		1									1	1
																	10	14	24	17	7		24							2		50	54
																		3	3	1			1									4	4
																				2	2		4							1		5	6
																								1					1			1	27
																		3	3	3	4	2	9		1				1			13	16
																				3	11	1	15		1				1			16	16
		1	1													1	6	4	10	11	7	1	19	4		1			5			34	40
																				2	2		4	1					1	5		10	10
																	3	1	4	3	1		4							1		9	9
																				2	3	3	8	1					1	2		11	11
																				4	11	2	17	1	1				2		1	20	20
																				1			1									1	1
																				1			1									1	12
	3	4	7	4	4	2	10		1		3		4	14	2	37	333	52	585	933	1449	291	2673	160	33	18	1	3	215	516	4	3993	8453

B

Table D-28. Component Versus Quantity Spilled Category G/D By Shore Code

SPILL QUANTITY CATEGORY / COMPONENT	GATHERING/DISTRIBUTION SYSTEM															
	ON-SHORE						OFF-SHORE					TOTALS				
	CODE	MINOR	MODERATE	MAJOR	UNKNOWN	TOTALS	MINOR	MODERATE	MAJOR	UNKNOWN	TOTALS	MINOR	MODERATE	MAJOR	UNKNOWN	TOTALS
Not Identified	00	3	293	70	26	392	5	9		4	18	8	302	70	30	410
Coupling	12		26	8		34	2				2	2	26	8		36
Disc, Rupture	16		1			1							1			1
Fasteners	18		3			3							3			3
Fittings	19		18	14		32							18	14		32
Flange	20		11	5		16							11	5		16
Float	21		1			1							1			1
Foundation	24			2		2								2		2
Gasket	25		36	3		39	2	1			3	2	37	3		42
Gasket Ring	26	1				1						1				1
Gauges	27							1			1		1			1
Gland, Packing	28		11	3		14							11	3		14
Header	30		4			4							4			4
Hose	34		2	2		4							2	2		4
Joint, Blast	36		1			1							1			1
Meters	40			5		5								5		5
Nipple	41		19	3	1	23	1				1	1	19	3	1	24
O-Rings	43		1			1		1			1		2			2
Packers	44		1			1							1			1
Pig	45						1	2			3	1	2			3
Pipe	46	44	2783	609	69	3496	3	4	1	2	10	47	2787	610	62	3506
Plug, Bull	48		6	5		11							6	5		11
Pump	49		7		5	12	4	6			10	4	13		5	22
Regulator, Pressure	52		1			1							1			1
Riser	55		4	1		5		1			1		5	1		6
Rods	56		2			2							2			2
Seals	59		6	1		7							6	1		7
Seam	60		1	2		3							1	2		3
Swage	65		2			2							2			2
Switches	66			1		1								1		1
Tank Shell	67		3	2	1	6							3	2	1	6
Tees	68		4	1	1	6							4	1	1	6
Threads	69		4	3	1	8							4	3	1	8
Tubing, Instrument	71		3	1		4							3	1		4
Union	72		2			2							2			2
Union, Flange	73		1			1							1			1
Valve	74		53	20		73	3	1			4	3	54	20		77
Valve, By-Pass	79		4			4							4			4
Valve, Check, Reverse Flow	80		64	2		66		2			2		66	2		68
Valve, Control	81		1			1							1			1
Valve, Gate	83		28	4		32							28	4		32
Valve, Relief, Pressure	86		2	2		4							2	2		4
Vessel, Pressure	88		1			1							1			1
Welds	89		8	17	1	26							8	17	1	26
Motor	91		1	2		3							1	2		3
Controls	93		2	3		5							2	3		5
Strainer	99		6	5		11							6	5		11
TOTALS		48	3427	796	96	4367	21	28	1	6	56	69	3455	817	102	4423

Table D-29. Component Versus Quantity Spilled Category Production by Shore Code

SPILL QUANTITY CATEGORY / COMPONENT	CODE	PRODUCTION SYSTEM														TOTAL
		ON-SHORE					OFF-SHORE					TOTAL				
		MINOR	MODERATE	MAJOR	UNKNOWN	TOTAL	MINOR	MODERATE	MAJOR	UNKNOWN	TOTAL	MINOR	MODERATE	MAJOR	UNKNOWN	
Not Identified	00	40	535	73	274	922	138	122	5	36	301	178	657	78	310	1223
Bell, Alarm	01		1			1	4	3			7	4	4			8
Blowcase, Saltwater	03	1	1			2	7	1			8	8	2			10
Box Stuffing	05	3	51		33	87	1				1	4	51		33	88
Cable	06		2			2							2			2
Choke Bean	07						2				2	2				2
Choke Body	08	2	4			6	4	7		1	12	6	11		1	18
Choke Target	09	2	1			3		1			1	2	2			4
Coil	10		1			1							1			1
Coupling	12	1	27		2	30	3	3			6	4	30		2	36
Detector, Heat	14						1				1	1				1
Diaphragm	15		2			2	1	1			2	1	3			4
Disc, Rupture	16	1	27	2	2	32	15	15			30	16	42	2	2	62
Ells	17	1	9			10	2	2			4	3	11			14
Fasteners	18		4			4	1	1			2	1	5			6
Fittings	19		19		4	23	2				2	2	19		4	25
Flange	20	2	4			6	8	5			13	10	9			19
Float	21		1			1	3	2			5	3	3			6
Float (Oil–Water)	23									1	1				1	1
Foundation	24		11	4		15							11	4		15
Gasket	25		9	1		10	1	5		1	7	1	14	1	1	17
Gauges	27		4	1		5	1	2		1	4	1	6	1	1	9
Gland, Packing	28	1	8		2	11	2	3			5	3	11		2	16
Glass, Sight	29		8			8		1			1		9			9
Header	30	1	6			7	1	2			3	2	8			10
Heater	31	2	4		5	11				1	1	2	4		6	12
Hose	34	1	10	2		13	11	5			16	12	15	2		29
Liner	39	1	3			4						1	3			4
Meters	40		6	2		8	1	1			2	1	7	2		10
Nipple	41	1	30		1	32	2	2			4	3	32		1	36
O–Rings	43		2			2	3	1			4	3	3			6
Packers	44		1			1	2	1		1	4	2	2		1	5
Pig	45		1			1			1		1		1	1		2
Pipe	46	58	875	46	61	1040	37	45	1	10	93	95	920	47	71	1133
Piston	47		1			1	1				1	1	1			2
Plug, Bull	48	2	8	1		11	2	2			4	4	10	1		15
Pump	49	2	36	2	10	50	20	22		4	46	22	58	2	14	96
Regulator, Pressure	52		5			5	2				2	2	5			7
Relay, Electric	53		1			1							1			1
Riser	55	2	2			4	5	1			6	7	3			10
Rods	56	1	3		1	5						1	3		1	5
Rod, Polished	57	1	7			8						1	7			8
Screen	58						1				1	1				1
Seals	59		1			1		2			2		3			3
Seam	60	1				1						1				1
Sensor, Level, High	61	3	13	1		17	27	46		3	76	30	59	1	3	93
Sensor, Level, Low	62	1				1	4	2			6	5	2			7
Sensor, Pressure High	63		2			2		4		4	8		6		4	10
Sensor, Pressure, Low	64							1		1	2		1		1	2
Swage	65		4			4							4			4
Switches	66	1	19	3		23	1	2			3	2	21	3		26
Tank Shell	67		30	7	11	48		1			1		31	7	11	49
Tees	68	1	4			5	1	2			3	2	6			8
Threads	69		3			3							3			3
Tubing Hanger	70							1			1		1			1
Union	72	2	9			11	4			1	5	6	9		1	16
Valve	74	7	197	34	20	258	17	21	1	3	42	24	218	35	23	300
Valve, Back Pressure	75		13			13	1	3		1	5	1	16		1	18
Valve, Ball	76							1		1	2		1		1	2
Valve, Body	78		2			2	1	3			4	1	5			6
Valve, By–Pass	79		2			2	1			1	2	1	2		1	4
Valve, Check, Reverse Flow	80		20	2	2	24	4	8			12	4	28	2	2	36
Valve, Control	81		6	1	1	8		2			2		8	1	1	10
Valve, Dump	82	16	102	12	3	133	38	48		3	89	54	150	12	6	222
Valve, Gate	83		5			5							5			5
Valve, Needle	84						1	3			4	1	3			4
Valve, Plug	85		1			1							1			1
Valve, Relief, Pressure	86	4	14			18	20	10		2	32	24	24		2	50
Valve, Trim	87						3	1			4	3	1			4
Vessel, Pressure	88		2			2		2		1	3		4		1	5
Welds	89			1		1								1		1
Motor	91		9	1		10	3				3	3	9	1		13
Fire–Tube	92		14	1		15		1			1		15	1		16
Controls	93	3	11	5		19	7	8			15	10	19	5		34
Vent	94		4	1	5	10							4	1	5	10
Test Tank	95	2	3			5	2	1		1	4	4	4		1	9
Oil Leg	96		8	1	2	11							8	1	2	11
Water Line/Leg	97		16	2	1	19		1			1		17	2	1	20
Fuel Supply Line/Leg	98		1			1							1			1
Strainer	99		1			1							1			1
TOTALS		167	2246	206	440	3059	419	430	8	78	935	586	2676	214	518	3994

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APPENDIX E

PRESENTATION OF SPILL DATA

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APPENDIX E

PRESENTATION OF SPILL DATA

E.1 INTRODUCTORY SUMMARY

E.1.1 Purpose and Scope

This appendix, drawing on the total spill data presented in Appendix D, is essential to the development of the spill prevention program described in this report. It presents analysis and discussion leading to the identification of spill vulnerable points of petroleum systems and spill prevention guidelines presented in Volume I . The analyzed data comprised 8473 total spill events distributed as shown in Table E-1.

Table E-1. Total Spill Events by System and Shore Code

System	Number of Spill Events		
	Offshore	Onshore	Total
Drilling System	18	19	37
Production System	935	3059	3994
Gathering/Distribution System	56	4367	4423
System not Identified	10	9	19
Total	1019	7454	8473

The data from Production and Gathering/Distribution (G/D) Systems are analyzed in this appendix (see Appendix B for System definitions and descriptions). Offshore data on the G/D System is minimal. The data includes experience from offshore California, Alaska, and the Gulf Coast. The gathering function for crude oil in the Gulf Coast (the dominant source of offshore data) is accomplished primarily by operator flowlines from offshore platforms to the shore, rather than by carrier G/D Systems. As a result, the G/D Systems' quantity is small compared to the data from the local flow and gathering subsystems of offshore production.

The data associated with either Drilling or unidentified systems are not analyzed here. The Drilling Systems' data has been examined and found not to contain trends significant to this study (see Tables D-19 and D-27 for presentation of Drilling System data). Reliance is placed on failure modes and fault tree analyses to develop spill prevention guidelines for drilling operations (see Appendix F).

E.1.2 Analytical Approach

The approach used in this study was to examine combined crude oil and condensate spill data separately for the Production and G/D Systems. Each system was examined by onshore and offshore applications and the reported spill size. Each spill event is defined in terms of a number of data elements (including geographic or administrative area) described by the Data Code Book, presented in Appendix K. The analysis, drawing data support from Appendix D as shown by Table E-2, was conducted through the following steps for each system's offshore and onshore data:

1. Identify subsystems with significant major or moderate spill experience.
2. Within each affected subsystem, identify equipment elements having significant spill experience.
3. For each affected equipment element, analyze the data for significant causes and components associated with the spill events, and prominent cause/component combinations and trends (e.g., geographic location, age of facility, time of year, and increasing or decreasing rate of occurrence).
4. For each affected subsystem, examine component/cause relationships for significant and prominent combinations and perform analyses similar to those of Step 3.
5. Examine, for all system spills (offshore, onshore, and combined), system components most often identified as responsible for the reported spills.
6. Examine, from the total system's spill data, the equipments most often identified as responsible for the reported spills.

Table E-2. Analysis Cross-Reference to Data Tabulations of Appendix D

Analysis	Table Title	Table No.
Component Versus System Elements	Component Versus System Elements, Moderate Spills Offshore	D-16
	Component Versus System Elements, Major Spills Onshore	D-17
Component Versus Cause	Component Versus Cause, G/D Systems, All Spills	D-18
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These analytical steps are designed to identify the spill vulnerable points of each system at system, subsystem, equipment, and component levels. The criteria of Table E-3 were used to evaluate these points in support of the methodology presented in Volume I.

Table E-3. Spill Criticality Rating Guide

Spill Criticality Rating	Criteria for Assignment
PRIORITY	Significant frequency of moderate or major spills based on historical data from present systems
ROUTINE	Significant spill frequency or significant (even if low frequency) cause/effect relationship responsible for major or moderate spills
POTENTIAL	Significant cause/effect relationship shown by engineering study of the system but not shown sufficiently in the spill data to merit a higher rating

E.1.3 Appendix Organization

Paragraph E.1 has provided an overview of all of the spill data, and outlined the general analytical approach. Paragraph E.2 provides the analysis for Production Systems' data following the analytical format previously outlined in Paragraph E.1.2. Paragraph E.3 provides, in similar format, the analysis for G/D System data. Paragraph E.4 presents an analysis at component level, of total spill events. Paragraph E.5 provides an analysis of spill events by quantity of spill. Paragraph E.6 provides an analysis of total spill events by reported cause of spill.

E.2 PRODUCTION SYSTEMS SPILL DATA ANALYSIS

E.2.1 An Overview of Data and Analytical Scope

The data to be analyzed comprised 3994 spill events distributed by subsystem and shore code as shown in Table E-4.

Table E-4. Production System Spill Events by Subsystem and Shore Code

Subsystem	Number of Spill Events		
	Offshore	Onshore	Total
31 Well	14	54	68
32 Wellhead	44	229	273
33 Gathering	169	1196	1365
34 Separation	211	166	377
35 Treater	142	393	535
36 Local Storage	185	734	919
37 Custody Transfer	17	73	90
38 Safety	39	6	45
39 Water Disposal	10	46	56
30 Not Identified	104	162	266
Total	935	3059	3994

The data appeared sufficient to support analyses for all subsystems. Offshore subsystem analysis is based on moderate spill data since only eight major offshore spills were reported. Onshore subsystem analysis is based on major spills where the data were sufficient and on both major and moderate spills where the data were insufficient. The following paragraphs present analyses of the subsystems.

E.2.2 Well Subsystem Analysis

The well subsystem performs the functions necessary to transport fluid from the producing formation to the surface of the earth. The subsystem includes the bore, casing string, production tubing, and downhole assembly, as applicable. The analyzed data comprised 68 spill events distributed by shore code and size of spill, as shown in Table E-5.

Table E-5. Well Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	4	1	5
Moderate	8	15	23
Major	0	2	2
Not Known	2	36	38
Total	14	54	68

The offshore analysis covered moderate spills while the onshore analysis examined moderate and major spills and spills of unreported quantity.

E.2.2.1 Offshore Well Subsystem Analysis

The eight moderate spill events exhibited no significant trend

E.2.2.2 Onshore Well Subsystem Analysis

The two major spills were reported from Texas and occurred during periods of wireline operation and repair/maintenance activity. The 15 moderate spills were distributed among six components and nine reported causes, and exhibited no significant trend. The 36 spills of unreported amount included 28 from Oklahoma. Each reported flow from an abandoned well. It is assumed, therefore, that changes in ground water pressure caused inadequately plugged wells to seep. The Oklahoma Corporation Commission (OCC) regulations (effective 1 January 1971) include Rule 3-400, which makes detailed provision for abandonment and plugging of wells under supervision of an authorized OCC representative.

E.2.3 Wellhead Subsystem Analysis

The wellhead subsystem (or Christmas tree) controls the produced fluids from the well to the production flowlines. The subsystem contains casing head equipment, tubing head equipment, fixed and adjustable chokes, artificial lift when used, and power equipment.

The analyzed data comprised 273 spill events distributed by shore code and size of spill as shown in Table E-6.

Table E-6. Wellhead Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	12	16	28
Moderate	28	136	164
Major	0	4	4
Not Known	4	73	77
Total	44	229	273

The offshore analysis considered moderate spills; the onshore analysis considered major and moderate spills.

E.2.3.1 Offshore Wellhead Subsystem Analysis

The 28 moderate spill events exhibited 10 instances of fixed choke or choke body being sand cut. All were in the Gulf Coast with the majority reported from the outer continental shelf (OCS). Four of these events were from the South Pass area.

E.2.3.2 Onshore Wellhead Subsystem Analysis

The four major spills exhibited no significant trend. However, one event in Texas occurred during workover (a major spill during wireline operations). The 136 moderate spill events were distributed among the wellhead equipments as shown in Table E-7.

Table E-7. Wellhead Subsystem Moderate Spill Events by Equipment

Equipment	Number of Moderate Spill Events
Rod Pump	41
Casing Head	22
Tubing Head	17
Fixed Choke	9
Other	6
Not Identified	41
Total	136

The trends exhibited by each equipment type in Table E-7 were as follows:

1. Rod Pump Equipment - The 41 events included 10 stuffing box leaks, including six due to overpressure, and nine valve leaks with a variety of causes and exhibited no significant trend. The stuffing box events were predominantly from Texas District 6 (see Appendix K for District definition).
2. Casing Head Equipment - The 22 events included nine valve events which exhibited no significant trend.
3. Tubing Head Equipment - The 17 events included five valve leaks which exhibited no significant trend.
4. Fixed Choke Equipment - The nine events included seven due to sand cutting and were predominantly from the New Orleans District.
5. Subsystem Component/Cause Combinations - The 136 spill events were distributed among components as shown in Table E-8.

Table E-8. Wellhead Subsystem Moderate Spill Events by Component

Component	Number of Moderate Spill Events
Stuffing Box	41
Valves	25
Other	54
Not Identified	16
Total	136

The 41 stuffing box events included 14 attributed to overpressure and 17 as leaking or failed. The 25 valve events were distributed among 14 different causes with the most significant being operational errors of leaving the valve in the incorrect open/close position. The valves left closed in error could contribute to the stuffing box failures from overpressure. No other subsystem component/cause combinations of significance were exhibited.

E.2.4 Gathering Subsystem Analysis

This discussion is limited to gathering subsystems of the Production Systems. Paragraph E.3 presents an analysis of Gathering/Distribution Systems and Paragraph E.3.5 discusses gathering subsystems of the Gathering/Distribution Systems. The gathering subsystem collects and transfers the produced fluids by flowline from the wellhead to required surface equipment in the Production System. The transported fluids contain wide variations in content of oil, gas, water, sand, parafin, and asphaltine, often stated summarily as a high basic sediment and water (BS & W) content, in comparison to the pipeline-quality oil (BS & W content limited to 1 percent) normally transported by the Gathering/Distribution System. The gathering subsystem contains flowline equipment, fixed and adjustable chokes, manifold equipment, metering, pumping and automatic control equipment, and power equipment. The analyzed data comprised 1365 spill events distributed by shore code and size of spill as shown in Table E-9.

Table E-9. Gathering Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	64	76	140
Moderate	90	1004	1094
Major	4	44	48
Not Known	11	72	83
Total	169	1196	1365

E.2.4.1 Offshore Gathering Subsystem Analysis

The four major spill events exhibited no trend. The 90 moderate spill events were distributed among flowline (61), manifold (5), and pump (23) equipment, with one not identified to an equipment. The 5 manifold exhibited no trend. The 23 pump included seven of burst gaskets, seals, and packing. The 61 flowline exhibited two trends; 11 of sandcut or flowcut pipe, fittings, and valves, and 26 involving pipe, of which 14 were described as leaking. Twelve of the 14 leaking pipe events, all reported from Gulf waters off Louisiana, were distributed by location and period of occurrence as shown in Table E-10.

Table E-10. Gathering Subsystem Moderate Spill Pipe Leaks by Location and Year

Location	Period of Occurrence		
	To 30 Jan. 1971	From 30 Jan. 1971	Total Spills
State Waters (22 months)	3 spills in 13 months	2 spills in 9 months	5
OCS (17 months)	6 spills in 8 months	1 spill in 9 months	7
Total Spills	9	3	12

Although the quantity of data is small, by inspection of the data, the spills due to leaking pipe in State waters occurred at the same rate (about three spills per year) before and after January, 1971. However, OCS data exhibited a decrease from nine spills per year to less than two per year after January, 1971. Provisions of Gulf OCS Order Number 8, issued by the USGS, require high and low pressure sensors close to the wellhead on flowlines from wellheads, effective 30 January 1971, to control abnormal pressure.

E.2.4.2 Onshore Gathering Subsystem Analysis

The major and moderate spills indicated that flowline equipment and, in particular, pipe events were dominant in gathering subsystem spills. Beyond this observation no significant trends were indicated at the subsystem level. Analyses of flowline equipment and component pipe are given in Paragraphs E.2.11 and E.4, respectively.

E.2.5 Separation Subsystem Analysis

The separation subsystem comprises equipment which separates produced liquids and gas. The equipment types used include high and low pressure separators and controls, and scrubbers with scrubber controls. Some applications use three-phase separators which perform the additional function of separating water from the produced fluids. The separator's function is to remove gas from the produced fluids. When a significant amount of gas is produced, a scrubber may be used to remove the relatively small quantity of liquid in the gasline before the gas is used, processed, or sent to a flare. Depending on the production conditions, some facilities use a single low pressure separator for one or several wells. Some facilities with high tubing pressure wells use two or more separation stages, in series, from high to low pressure. Other facilities with high volume production or with both high and low pressure wells use parallel separation paths to handle the flow. The analyzed data comprised 377 spill events distributed by shore code and size of spill as shown in Table E-11.

Table E-11. Separation Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	100	21	121
Moderate	100	126	226
Major	0	11	11
Not Known	11	8	19
Total	211	116	377

E.2.5.1 Offshore Separation Subsystem Analysis

Moderate spill events for the separation subsystem were distributed among the equipments as shown in Table E-12.

Table E-12. Separation Subsystem Moderate Spill Events by Equipment

Equipment	Number of Spill Events
Low Pressure Separators	42
Low Pressure Separator Controls	12
High Pressure Separator	7
High Pressure Separator Controls	4
Scrubbers	6
Scrubber Controls	2
Not Identified	27
Total	100

The scrubbers provided insufficient data to support analysis. The 54 spill events from low pressure separators and controls presented three trends of interest: 13 dump valves which failed to open, close, or function; nine high level sensors which failed to function; and 11 pressure relief valves and rupture discs which burst, failed open, or overflowed. The data do not distinguish between rupture disc actions as normal protective action and those due to disc deterioration or misapplication. The 11 spill events from high pressure separators and controls exhibited one significant finding: six were attributed to dump valves, and five of these failed as a result of sand or flow cutting.

E.2.5.2 Onshore Separation Subsystem Analysis

The 11 major spill events exhibited no trends. The 126 moderate spill events were dominated by failures of dump valves (38) and rupture discs (23). The dump valve events included 27 with cause reported as failed upon, failed closed, and nonfunction. The rupture disc events included 20 with cause reported as burst. No information was given to indicate whether rupture disc action was due to deterioration or misapplication of the disc, or due to normal protective action in response to abnormally high pressure in the separator. Only 13 of the spill events were assigned to high pressure separator and scrubber equipment. The data exhibited no significant indication of sand or flow cutting in either the high pressure separators or elsewhere in this analysis.

E.2.6 Treater Subsystem Analysis

The treater subsystem treats and conditions the crude oil for emulsion and provides for separation of produced water and oil. The subsystem includes heater treaters and controls, chemical-electric treaters and controls, gun barrels, skimmers, free water knock out (FWKO), and power equipment. The treaters and gun barrel separators break down the oil/water emulsion and separate the water from the produced fluid. When the well produces a high cut of free water (water which will separate from the oil and emulsion by gravity within 5 minutes and without heat or chemical treatment), the facility may use FWKO equipment to separate out the free water before sending the fluids to the treater. The skimmer is used to retain the relatively small quantity of crude oil from the water discharged from the treater subsystem and prior to water disposal. The analyzed data comprised 535 spill events distributed by shore code and size of spill as shown in Table E-13.

Table E-13. Treater Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	63	22	85
Moderate	67	306	373
Major	0	38	38
Not Known	12	27	39
Total	142	393	535

E.2.6.1 Offshore Treater Subsystem Analysis

The 67 moderate spill events were distributed among all of the equipments with heater treaters (22 events) being the most frequently identified and chemical-electric treaters (five events) being the least frequently identified. The most prominent trend with all equipments was 18 spill events attributed to dump valves, with 16 either failed open, failed closed, or nonfunctioning. Of these, 10 were specifically identified as failed open. For the facilities visited (see Appendix A), instrument gas for valve operation was drawn from a separate supply rather than from the treater itself, thus providing protection against loss of instrument gas pressure when the treater dump valve hangs open. Thus, spillage resulting from an open dump valve is believed to have involved the salt water dump valve with a subsequent overflow of oil from the skimmer tank.

A second trend resulted from nine spill events due to high level sensors. The cause of most of these events was reported as nonfunction and was attributed to heater treaters. Failure of the oil level sensor would allow oil to flow out the gasline. Failure of the level sensor at the oil-water interface would cause water to flow with the oil out the oil leg and possibly overflow the oil tank. It is also possible for the same malfunction to cause oil to overflow the gas line if the oil leg could not handle the entire flow of oil and salt water. A third (and minor) trend involved bursting of four rupture discs.

E.2.6.2 Onshore Treater Subsystem Analysis

The 38 major spills included 23 attributed to heater treaters and controls, with the remainder distributed among the chemical-electric treaters, gun barrels, skimmers, and FWKO equipment. Only the heater treater equipment reflected a trend. That trend consisted of six dump valve spill units, including five attributed to fail open, fail closed, and nonfunction causes. The 306 moderate spill events included 211 attributed to heater treaters and controls, with the remainder distributed over the other subsystem equipments. Only the heater treaters and control equipment exhibited trends of significance. Dump valve events (32) were reported in fail open, fail closed, and nonfunction modes. Fire tube events (14) were reported for leaking. Pipe events (16) were reported as being plugged. A number of valve events (28) were reported over a variety of causes and exhibited no significant trend.

E.2.7 Local Storage Subsystem Analysis

This discussion is limited to production storage subsystems. Paragraph E.3.3 presents a discussion of storage subsystems of the Gathering/Distribution Systems. The storage subsystem provides for the local storage of produced oil until guaging or metering and sale of the oil (usually to a pipeline) occurs. The system includes tanks, firewalls, tank-associated equipment, sump (when applicable), and power equipment. The analyzed data comprised 919 spill events distributed by shore code and size of spill as shown in Table E-14.

Table E-14. Storage Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	99	21	120
Moderate	74	486	560
Major	2	85	87
Not Known	10	142	152
Total	185	734	919

Offshore analysis considered moderate spills; onshore analyses considered major spills.

E.2.7.1 Offshore Storage Subsystem Analysis

The 74 moderate spill events were predominantly assigned to tanks (14), tank associated equipment (23), and sump equipment (36). Among these events, three trends were exhibited:

1. Nonfunctioning high level sensors were prominent for both storage tanks and sump systems.
2. Nonfunctioning pumps were predominant in sump systems and, to a lesser degree, in storage tanks.
3. Tank and sump spill events reported overflow as predominant.

The sump events were reported only for the Gulf Coast OCS. Gulf OCS Order Number 8 requires a sump with control of level but does not require inspection or test of the pumps. Louisiana requires a sump or other suitable means of containment, but does not require level control or specific inspection or test.

E.2.7.2 Onshore Storage Subsystem Analysis

The 85 major spill events were predominantly assigned to tanks (59), tank-associated equipment (19), and sump equipment (4). No trends were exhibited among the tank-associated equipment or sump events. The 59 tank events included 20 of tank and tank shell leak. Only four were reported for overflow. The spill was contained within a firewall in only eight instances and the spill was trapped in a natural depression in only five instances. The 486 moderate spill events were examined and exhibited the same trends as for the major spill events.

E.2.8 Custody Transfer Subsystem Analysis

The custody transfer subsystem monitors BS & W content, meters fluid flow, and transfers crude oil from production storage to sales or pipeline. The subsystem contains pumps and pump controls, metering equipment, manifold and sampling equipment, prover tanks and associated equipment, and power equipment. In nonautomated custody transfer functions, gauger and trunk transfer activity may be considered in series with the applicable hardware. The data to be analyzed comprised 90 spill events distributed by shore code and spill size as shown in Table E-15.

Table E-15. Custody Transfer Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	7	2	9
Moderate	8	66	74
Major	1	5	6
Not Known	1	0	1
Total	17	73	90

E.2.8.1 Offshore Custody Transfer Subsystem Analysis

The eight moderate spill events included four instances of loss of pumping function for different causes. No trends of significance were exhibited.

E.2.8.2 Onshore Custody Transfer Subsystem Analysis

The five major spill events exhibited no trend of significance. The 66 moderate spill events exhibited 11 instances of electrical malfunction or power loss as the only trend of significance.

E.2.9 Safety Subsystem Analysis

The safety subsystem monitors and shuts down any phase of the production, or all production in an emergency, and provides visual and audible alarms in the event of undesired system operation or condition. The subsystem contains energy source (e.g., instrument gas) and distribution equipment, sensing and detecting equipment, monitoring and alarm equipment, subsurface safety valves, and high/low pressure valves. In general, a spill event attributed to the safety subsystem requires a discrepancy elsewhere in the system (which places a demand for safety system operation) in addition to a failure within the safety subsystem itself. The data to be analyzed comprised 45 spill events distributed by shore code and spill size as shown in Table E-16.

Table E-16. Safety Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	13	0	13
Moderate	21	5	26
Major	1	1	2
Not Known	4	0	4
Total	39	6	45

E.2.9.1 Offshore Safety Subsystem Analysis

The 21 moderate spill events included four attributed to high level sensors and four attributed to valves which did not function. No significant trend was observed.

E.2.9.2 Onshore Safety Subsystem Analysis

The five moderate spill events included three occasions of high level sensors failing to function.

E.2.10 Water Disposal Subsystem Analysis

The water disposal subsystem provides for the disposal of produced water through water processing equipment to meet various requirements prior to water disposal or injection. The subsystem includes, as appropriate, filters, clarifying tanks, flotation cells, oxygen stripping tanks, settling pits or tanks, power equipment, and injection wells. The analyzed data comprised 56 spill events distributed by shore code and size of spill as shown by Table E-17.

Table E-17. Water Disposal Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	4	6	10
Moderate	4	34	38
Major	0	5	5
Not Known	2	1	3
Total	10	46	56

E.2.10.1 Offshore Water Disposal Subsystem Analysis

The four moderate spill events exhibited no trends.

E.2.10.2 Onshore Water Disposal Subsystem Analysis

The five major spills exhibited no trends. The 34 moderate spill events identified malfunctioning pumps as the dominant trend. No other trend of significance was exhibited.

E.2.11 Analysis of Total Equipment Spills for the Production System

A detailed record of spill events reported against the Production System is presented in Table E-18. Each system, subsystem, and equipment element is shown with the number of events or failures reported for that element. To provide a measure of each element's performance, Table E-18 also includes a percentage of contribution to the higher levels. Subsystem events are shown as a percentage of total combined events for all systems and total reported Production System events. Equipment failures are shown as a percentage of total Production System and subsystem events.

Table E-19 presents a ranking of Production System equipments from Table E-18 that caused significant numbers of system events. It was necessary to analyze the data on lower tier equipment and component events to identify those that represent significant problem areas at the subsystem level. Table E-19 shows that flowline equipment accounted for the majority of events with 30.54 percent followed by tanks with 11.54 percent. The remaining events were distributed among the rest of the equipment with no equipment accounting for more than 10 percent of the events reported.

Table E-19. Ranking of Production System Equipment by Number of Reported Spill Events

Equipment	Subsystem	No. of Spill Events	% of Total Events	% System Events
Flowline Equipment	Gathering	1220	14.43	30.54
Tanks	Storage	461	5.45	11.54
Tank Associated Equipment	Storage	335	3.96	8.39
Heater Treater	Treater	265	3.13	6.63
Separator L. P.	Separation	157	1.86	3.93
Pumps	Gathering	103	1.22	2.58

Approximately 88 percent of the spill events for flowline equipment involved pipe (Table E-20). The major cause was leaking, accounting for about 54 percent. Leaks were due to material failure caused by corrosion.

Table E-20. Flowline Equipment Spill Events by Component and Cause (1220 Events Reported)

Cause	Code	Pipe	Not Ident.	Valves	Coupling	Check Valve	Nipple	Union	Total
Code	--	46	00	74	12	80	41	72	---
Leaking	26	375	24	7	7	--	3	6	422
Broken	12	91	20	4	--	--	6	--	121
Farm Machinery	93	--	--	4	--	--	--	--	4
Valve Opened	98	--	--	4	--	--	--	--	4
Hole	25	92	--	--	--	--	--	--	92
Corroded	15	65	--	--	--	--	--	--	65
Burst/Ruptured/ Split	14	60	8	--	--	4	--	--	72
Parted, Line	33	--	--	--	5	--	--	4	9
Total	--	683	52	19	12	4	9	10	789

Table E-18. Production System Spill Events by Subsystem and Equipment

ELEMENTS	QUANTITY OF EVENTS	% TOTAL EVENTS	% SYSTEM EVENTS	% SUBSYSTEM EVENTS
Well Subsystem	70	0.83	1.75	100.00
Bore	32	0.38	0.80	45.71
Casing String	7	0.08	0.18	10.00
Production Tubing	9	0.11	0.23	12.86
Downhole Assembly	2	0.02	0.05	2.86
Equipment Not Identified	20	0.24	0.50	28.57
Well Head Subsystem	272	3.22	6.81	100.00
Casing Head Equipment	30	0.35	0.75	11.03
Tubing Head Equipment	77	0.91	1.93	28.31
Choke Fixed	28	0.33	0.70	10.29
Choke Adjustable	0	–	–	–
Rod Pump	60	0.71	1.50	22.06
Hydraulic Lift	2	0.02	0.05	0.74
Gas Lift	4	0.05	0.10	1.47
Electric Pump	0	–	–	–
Power Equipment	3	0.04	0.08	1.10
Equipment Not Identified	68	0.80	1.70	25.00
Gathering Subsystem	1370	16.21	34.29	100.00
Flowline Equipment	1220	14.43	30.54	89.05
Choke Fixed	3	0.04	0.08	0.22
Choke Adjustable	0	–	–	–
Manifold	29	0.34	0.73	2.12
Metering	4	0.05	0.10	0.29
Pumps	103	1.22	2.58	7.52
Automatic Control Equipment	3	0.04	0.08	0.22
Power Equipment	0	–	–	–
Equipment Not Identified	8	0.09	0.20	0.58
Separation Subsystem	377	4.46	9.44	100.00
Separator, High Pressure	18	0.21	0.45	4.77
Separator Control, H.P.	13	0.15	0.33	3.45
Separator, Low Pressure	157	1.86	3.93	41.64
Seperator Control, L.P.	40	0.47	1.00	10.61
Scrubber	31	0.37	0.78	8.22
Scrubber Control	4	0.05	0.10	1.06
Equipment Not Identified	114	1.35	2.85	30.24
Treater Subsystem	530	6.27	13.27	100.00
Heater Treater	265	3.13	6.63	50.00
Heater Treater Control	37	0.44	0.93	6.98
Chem–Elect Treater	12	0.14	0.30	2.26
C–E Treater Control	7	0.08	0.18	1.32
Gun Barrel	85	1.01	2.13	16.04
Skimmer	43	0.51	1.08	8.11
Free Water Knockout	37	0.44	0.93	6.98
Power Equipment	2	0.02	0.05	0.38
Equipment Not Identified	42	0.50	1.05	7.92
Local Storage Subsystem	925	10.94	23.15	100.00
Tanks	461	5.45	11.54	49.84
Tank Associated Equipment	335	3.96	8.39	36.22
Sump Equipment	70	0.83	1.75	7.57
Firewall	7	0.08	0.18	0.76
Power Equipment	4	0.05	0.10	0.43
Equipment Not Identified	48	0.57	1.20	5.19
Custody Transfer Subsystem	91	1.08	2.28	100.00
Pumps	15	0.18	0.38	16.48
Pump Controls	8	0.09	0.20	8.79
Metering Equipment	15	0.18	0.38	16.48
Manifold	5	0.06	0.13	5.49
Sampling Equipment	1	0.01	0.03	1.10
Prover Tank	9	0.11	0.23	9.89
Power Equipment	7	0.08	0.18	7.69
Equipment Not Identified	31	0.37	0.78	34.07
Safety Subsystem	44	0.52	1.10	100.00
Energy Source	2	0.02	0.05	4.55
Energy Distribution Equipment	2	0.02	0.05	4.55
Sensing & Detecting Equipment	6	0.07	0.15	13.64
Monitoring & Alarm Panel	2	0.02	0.05	4.55
Electrical Equipment	1	0.01	0.03	2.27
Subsurface Safety Valve	1	0.01	0.03	2.27
Subsurface Cont'd Subsurface Safety Valve	0	–	–	–
Hi–Lo Pressure Valve	1	0.01	0.03	2.27
Equipment Not Identified	29	0.34	0.73	65.91
Water Disposal Subsystem	57	0.67	1.43	100.00
Power	10	0.12	0.25	17.54
Precipitator	6	0.07	0.15	10.53
Equipment Not Identified	41	0.49	1.03	71.93
Subsystem/Equipment Not Identified	258	3.02	6.38	N/A
Total Production System	3995	47.26	100.00	N/A
Total Failures–All Systems	8453	100.00	N/A	N/A

The second major category associated with flowline equipment events was "not identified" (i.e., components were not identified in the data sources). The causes associated with this group could also result from corrosion. The third-ranked component was valves. Of the 19 events caused by valves, 42 percent were caused by a third party and 58 percent were caused by material failure. All of the other component events were caused by a material failure.

Of the reported tank events, leaking and hole accounted for about 35 percent (Table E-21.) In about 80 percent of these cases the component involved was not identified. All valve events were caused by third party or operator error. Most of the tank shell and foundation events were attributed to leak and hole. The data sources did not provide information as to why the tanks leaked or had holes.

Table E-21. Tank Equipment Spill Events by Component and Cause (461 Events Reported)

Cause	Code	Not Ident.	Valve	Tank Shell	Foundation	Total
Code	--	00	74	67	24	--
Leaking	26	71	--	7	10	88
Overflowed	31	73	--	--	--	73
Hole	25	59	--	16	--	75
Lightning	77	32	--	--	--	32
Not Reported	03	29	--	--	--	29
Valve Open/Closed	98	--	5	--	--	5
Vandalism	99	--	5	--	--	5
Left Open	48	--	4	--	--	4
Incorrect Operation	51	--	4	--	--	4
Burst/Ruptured/ Split	14	--	--	5	--	5
Corroded	15	--	--	5	--	5
Total	--	264	18	33	--	325

For tank associated equipment, valves and pipe contributed the most spill events, 11.6 percent (Table E-22). However, 82 percent of the valve events were caused by operator error or third party damage and 18 percent were a result of material failure. All of the pipe events were a result of material failure. Three percent of the components could not be identified and were attributed to personnel error. Pump events caused 3 percent of the events reported

Table E-22. Tank Associated Equipment Spill Events by Component and Cause (335 Events Reported)

Cause	Code	Valve	Pipe	Not Ident.	Pump	Total
Code	--	74	46	00	49	--
Left Closed	47	13	--	--	--	13
Left Open	48	10	--	--	--	10
Livestock	95	9	--	--	--	9
Failure Closed	23	7	--	--	--	7
Leaking	26	--	12	--	--	12
Hole	25	--	11	--	--	11
Broken	12	--	8	--	--	8
Plugged	34	--	8	--	--	8
Improper Maint.	50	--	--	5	--	5
Incorrect Operation	51	--	--	5	--	5
Equip. Failure	10	--	--	--	6	6
Nonfunctioning	30	--	--	--	5	5
Total	--	39	39	10	11	99

Of heater treater events, dump valves were a major contributor, accounting for 13.6 percent (Table E-23). Other valves were second, contributing approximately 8.7 percent. However, since the data sources did not specify the type of valves, they could also be dump valves. Pipe and rupture discs ranked third and fourth, respectively. No other component reported a significant number of events.

Table E-23. Heater Treater Equipment Spill Events by Component and Cause (265 Events Reported)

Cause	Code	Not Ident.	Valve	Dump Valve	Pipe	Disc Rupture	Total
Code	--	00	74	82	46	16	--
Equip. Failure	10	17	17	--	--	--	34
Leaking	26	12	--	--	--	--	12
Nonfunctioning	30	11	--	6	--	--	17
Hole	25	8	--	--	--	9	17
Overflowed	31	6	--	--	--	--	6
Not Reported	03	--	6	--	--	--	6
Failure Opened	22	--	--	20	--	--	20
Failure Closed	23	--	--	10	--	--	10
Plugged	34	--	--	--	8	--	8
Total	--	54	23	36	8	9	130

Of the 157 events reported against separator, low pressure, disc rupture accounted for 15.3 percent (Table E-24). The cause of events in all cases was burst or ruptured. Since the function of the disc is to rupture under excess pressure, the initial cause of the event should be attributed to some other component. However, the data sources did not provide enough information to determine the responsible component.

Table E-24. Separator, Low Pressure Equipment Spill Events by Component and Cause (157 Events Reported)

Cause	Code	Not Ident.	Dump Valve	Disc Rupture	Relief Valve	Hi Level Sensor	Total
Code	--	00	82	16	86	61	--
Overflowed	31	15	--	--	6	--	21
Nonfunctioning	30	9	6	--	--	9	24
Equip. Failure	10	6	--	--	--	--	6
Sand Cut	19	--	5	--	--	--	5
Failure Closed	23	--	5	--	--	--	5
Burst/Ruptured/Split	14	--	--	24	--	--	24
Total	--	30	16	24	6	9	85

The largest component event category for pumps was "not identified" with 13 (Table E-25). The identified component with the most events was packing gland. The remaining 103 events reported on pump were distributed among many components.

Table E-25. Pump Equipment Spill Events by Component and Cause (103 Events Reported)

Cause	Code	Not Ident.	Pipe	Packing Gland	Pump	Total
Code	--	00	46	28	49	--
Nonfunctioning	30	7	--	--	--	7
Equip. Failure	10	6	--	--	--	6
Burst/Ruptured/ Split	14	--	4	4	--	8
Leaking	26	--	--	4	4	8
Total	--	13	4	8	4	29

E.3 GATHERING/DISTRIBUTION SYSTEMS SPILL DATA ANALYSIS

E.3.1 An Overview of Data and Analytical Scope

The analyzed data comprised 4423 spill events distributed by subsystem and shore code as shown in Table E-26.

Table E-26. Gathering/Distribution System Spill Events by Subsystem and Shore Code

Subsystem	Number of Spill Events		
	Offshore	Onshore	Total
Pipeline	44	3182	3226
Storage	2	136	138
Pump Station	5	160	165
Safety	1	2	3
Gathering	2	868	870
Not Identified	2	19	21
Total	56	4367	4423

For offshore events, only the pipeline subsystem was analyzed; the remaining subsystems were examined and found not to exhibit any significant trends. For onshore events, the pipeline, storage, pump station, and gathering subsystems had sufficient data. The data for the unidentified subsystems was examined and found to contain no information deemed significant to the study.

E.3.2 Analysis of Pipeline Subsystem

The pipeline subsystem comprises the manifold and distribution network through which pipeline-quality crude oil is transported to a refinery or other terminal facility. When the data specifically indicated that a spill was associated with a gathering function, it was assigned to the gathering subsystem. Otherwise, the spill event was associated to this subsystem which comprises equipment elements identified as pipe, scraper trap, pipe support structure, stream crossings, and road crossings. The analyzed data comprised 3226 spill events, distributed by shore code and size of spill, as shown in Table E-27.

Table E-27. Pipeline Subsystem Spill Events by Spill Category and Shore Code

Spill Category	Number of Spill Events		
	Offshore	Onshore	Total
Minor	19	36	55
Moderate	21	2429	2450
Major	1	634	635
Not Known	3	83	86
Total	44	3182	3226

E.3.2.1 Offshore Pipeline Subsystem Analysis

The 21 moderate spill events did not exhibit any significant trends at the equipment level. Two component/cause combinations were exhibited; overflow as a result of pumps failing to function (four), and overpressure within the subsystem itself (three). These events are associated with Gulf OCS operations with none reported in Louisiana State waters. This may have been a result of high and low pressure shut-in devices for pipeline pumps required (effective 30 April 1971) by OCS Order Number 9, but not specifically required Louisiana Title 30 Stream Control Regulations. The increased sophistication required for OCS facilities could increase the opportunity for equipment malfunction and spills to be exhibited in the data; the benefits of reduced spill frequency due to added protection against unusual pipeline pressure could not be evaluated. It is not clear from the data whether these events occurred in an offshore gathering pipeline or in operator production flowlines from the platforms to the offshore pipeline.

E.3.2.2 Onshore Pipeline Subsystem Analysis

Pipe and road crossing equipment were analyzed; the other equipment categories had insufficient data to support analysis.

E.3.2.2.1 Pipe Equipment

1. Component Analysis - Of the 634 major subsystem spills, 614 were attributed to pipe equipment and distributed among components as shown in Table E-28.

Table E-28. Pipe Equipment Onshore
Major Spill Events by Component

Component	Number of Major Spill Events
Pipe	513
Welds	13
Fittings	11
Valves	9
Other	29
Not Identified	39
Total	614

An examination was made of data for welds, fittings, valves, and equipment events not identified. None showed a significant trend from the major spill events, but did show repetitive events attributed to bursting and rupture from the moderate spill events.

2. Analysis of Reported Cause - The 614 pipe equipment spill events are distributed by cause as shown in Table E-29.

Table E-29. Pipe Equipment Onshore Major Spill Events by Cause and Component

Cause	Code	Component			
		Pipe	Other	Not Identified	Total
Code	--	46	N/A	00	--
Burst	14	35	4	3	42
Corrosion	15	41	0	6	47
External Corrosion	16	155	2	5	162
Internal Corrosion	17	50	1	8	59
Defective Material	20	24	6	0	30
Leak	26	15	1	5	21
Defective Weld	39	19	8	0	27
O/M Error	40	9	5	2	16
Natural Causes	70	12	2	0	14
Third Party (Other)	90	24	0	0	24
Farm Machinery	93	14	0	2	16
Road Machinery	96	69	3	2	74
Other	--	46	30	6	82
Total	--	513	62	39	614

The spills for component pipe will be analyzed for the causes identified in Table E-29. A total of 107 spill events due to a third party are presented. Those attributed to road machinery (69 events) and farm machinery (14 events) are shown separately. All other reported third party causes account for the remaining 24 spill events.

3. Analysis of Pipe Cause Combinations

   a. Burst - Of the 35 reported events, 12 occurred in Texas, six in Mississippi, and four in Colorado. The Texas events occurred during normal operation and without seasonal or geographic trend. Most spills were from large (6-inch or larger) diameter pipe. No significant trends were observed in the Mississippi or Colorado events.

b. Corrosion - Of the 41 events related to corrosion (as distinguished from the more specific causes of external or internal corrosion) 27 occurred in Texas and 12 in Mississippi. The Texas events occurred most frequently from April through September. District 4 (see Appendix K) accounted for 10 of the Texas events, with nine in the April through September period. The Mississippi events occurred from large diameter pipe mostly from October through March. None showed substantial recovery of oil.

c. External Corrosion - The 155 events are distributed by State in Table E-30.

Table E-30. Pipe Component Onshore Major Spill Events Attributed to External Corrosion (by State)

State	Number of Major Spill Events
Illinois	10
Indiana	9
Louisiana	7
Mississippi	4
New Mexico	4
Ohio	8
Oklahoma	8
Pennsylvania	9
Texas	82
Other	14
Total	155

(1) Illinois - The 10 spill events affected pipe installed in the 1930s. In seven events the pipe was under cathodic protection and in nine events it was coated.

(2) Indiana - The nine spill events appeared in two groups: pipe installed before 1920 in Lake, Porter, and Fulton Counties without cathodic protection or coating; and pipe installed between 1930 and 1950 in Wayne, Putnam, Shelby, and Vigo Counties with cathodic protection but uncoated.

(3) Louisiana - Most of the seven events were for pipe laid in the 1940s in the Lafayette District. In five events the pipe was under cathodic protection. In all events the pipe was uncoated.

(4) Mississippi - The four events were from pipe laid in the 1950s in Perry and Lamar Counties. None were coated or under cathodic protection.

(5) New Mexico - The four events were from pipe installed in the 1930s in Lea County. All affected pipe was under cathodic protection and one event was reported for coated pipe.

(6) Ohio - Of the eight events, five occurred in pipe laid in Trumbull County prior to 1920, with no protection. Three occurred in pipe laid in Wood County between 1920 and 1950 with one event reporting cathodic protection. The pipe was not coated in any of these events.

(7) Oklahoma - The eight events primarily from Districts 1 and 4 (see Appendix K), included three with coating and cathodic protection, two with cathodic protection only, and two with no protection. Six of the events occurred in pipe laid between 1920 and 1940.

(8) Pennsylvania - All nine events were reported for pipe laid in Clarion, Butler, and McKean Counties before 1920 and without protection.

(9) Texas - Of the 82 events, 38 reported information concerning the status of the pipe. Of these 38, nine had coating and cathodic protection, 13 had either coating or cathodic protection, and 16 had no protection. The pipe ranged in age from before 1920 through the 1960s without significant trend between age and protection provided.

d. Internal Corrosion - The 50 events included five from Montana and 39 from Texas. The five from Montana occurred in pipe laid in the 1950s in Wibaux County. In all events the pipe had both coating and cathodic protection. The 39 Texas events are discussed in two groups

(1) In one group of 26 events, 22 occurred in Districts 7, 8 and 10 (see Appendix K). Four events in District 10 occurred in pipe laid in the 1960s coated and under cathodic protection. All occurred in large (6-inch or larger) diameter pipe and were reported for October and November.

(2) In a second group of 13 events, 11 occurred in pipe with coating and cathodic protection.

It may be significant that most instances of internal corrosion occurred in pipe with both coating and cathodic protection. Two possible explanations are offered:

(1) External corrosion is exhibited by the data at about three times the frequency of internal corrosion. Coated and cathodically protected pipe will resist external corrosion to such an extent that internal corrosion has an opportunity to damage the pipe, whereas unprotected pipe can experience external corrosion before the effects of internal corrosion are significant.

(2) The protective coatings and cathodic protection (and possibly ground potential conditions generating a requirement for protection against external corrosion) may create conditions capable of accelerating existing mechanisms of internal corrosion. No experience or support for this possibility was obtained from consultation with industry representatives.

e. Defective Material - Eighteen of the 24 reported events occurred in Kansas, Montana, Oklahoma, and Texas. Pipe installation dates ranged from 1920 through the 1960s.

f. Leak - These 15 events were primarily from Texas with District 7 being most prominent. Pipe age and protection information were not reported.

g. Defective Weld - Eleven of these 19 events were reported in Oklahoma on pipe installed between 1930 and 1950. In all events the pipe was coated; the status of cathodic protection was not reported. The distribution of these events by type of weld, i.e., longitudinal (factory) and girth (field), was not determined.

h. Operation and Maintenance Error - No trend was observed in the nine events reported.

i. Natural Causes - Of the 12 events reported, five were attributed to flooding. No other trend was observed.

j. Third Party - The most prominent third party action reported was damage from road machinery with 69 events, including 44 from Texas and 11 from Oklahoma. No other trends were exhibited.

E.3.2.2.2 Road Crossing Equipment

Of the 634 onshore major spills in Table E-28, 16 were attributed to road crossing equipment. Of the 16 events, 15 were reported for pipe with predominant causes being corrosion (five) and road machinery (eight). The corrosion events were all reported from

Colorado, and all were sited for violation of regulations. Only one has occurred since 1970. Of the road machinery events, five were reported from Texas. No other trends were exhibited.

E.3.3 Storage Subsystem Analysis

This discussion is limited to storage subsystems of Gathering/Distribution (G/D) Systems. Production storage subsystems are discussed in Paragraph E.2.7. The storage subsystem comprises a temporary storage or holding facility for incoming crude oil pending transshipment. The subsystem is divided into equipment elements of tank, tank firewall, tank-associated equipment, power equipment, and equipment not identified. As previously indicated, only onshore data are of sufficient quantity to support analysis. The analyzed data comprised 136 events distributed by size of spill, as shown in Table E-31.

Table E-31. Storage Subsystem Onshore Spill Events by Spill Category

Spill Category	Number of Spill Events
Minor	1
Moderate	96
Major	38
Not Known	1
Total	136

The 38 major spills were examined and found to contain 32 events for the equipment tank and six events for tank-associated equipment. Seventeen events were distributed among nine components. These included five valve failures due to four different causes, and four meter failures due to three different causes. Twenty-one tank failures were distributed over 13 causes with not more than three repetitions of any single cause. As a result, no significant trend was found. However, tank and tank-associated equipment are among the top five equipments in frequency of total spills and will be analyzed on the basis of total spills in Paragraph E.3.6.

E.3.4 Pump Station Subsystem Analysis

The pump station subsystem comprises the means for pumping and controlling the flow of crude oil during transfer through the G/D System. The subsystem is divided into 19 equipment elements as defined in Appendix B. The analyzed data comprised 160 events distributed by size of spill as shown in Table E-32.

Table E-32. Pump Station Subsystem Onshore Spill Events by Spill Category

Spill Category	Number of Spill Events
Minor	1
Moderate	111
Major	38
Not Identified	10
Total	160

The 38 major spill events were distributed among six equipment elements, 18 causes, and 16 components with only one combination of more than two occurrences. The single combination represented three events of a plugged pump strainer. As a result, no trends of significance were exhibited. However, pump equipment in this subsystem is among the top five equipments in frequency of total spills. It will be analyzed on the basis of total spills in Paragraph E.3.6.

E.3.5 Gathering Subsystem Analysis

This discussion is limited to gathering subsystems of the Gathering/Distribution System. Production gathering subsystems were discussed in Paragraph E.2.4. The gathering subsystem comprises the network of pipelines and associated manifolding which gathers crude oil from the oil fields and brings it to a central gathering point. If the function in a reported spill event is not specifically identified as gathering, the event is assigned to the pipeline subsystem. The gathering subsystem is subdivided by type of facility rather than equipment, as for the other subsystems. The type breakdown is made for gravity, suction, pressure, and not identified. As previously indicated, only onshore data provided support for analysis. The analyzed data comprised 868 events distributed by size of spill, as shown in Table E-33.

Table E-33. Gathering Subsystem Onshore Spill Events by Spill Category

Spill Category	Number of Spill Events
Minor	8
Moderate	775
Major	83
Not Known	2
Total	868

This analysis covered the group of major spill events. Of these 83 events, 69 were reported with system type not identified. An inspection of the data indicated that no significant trends may be found by facility type. Seventy-four of the 83 events were identified to the component pipe. The remaining nine were distributed among several other components with no additional component trends indicated. The 74 component pipe spill events are distributed by cause in Table E-34. The causes exhibiting trends with the component pipe were:

1. Burst - All six events occurred in Texas from large (6-inch diameter or larger) pipe. No other trends were exhibited.
2. Corrosion - All 21 events occurred in Texas. No further trends were indicated from the data.
3. Internal Corrosion - The 16 events were reported from Texas Districts 8 and 9, primarily in the winter months.
4. External Corrosion - The seven events were reported from Texas, from large diameter pipe. No data on pipe age or protection was reported. No other trends were exhibited.

5. Third Party - The 12 third party events included eight attributed to road machinery damage. These eight were reported from Texas with the majority reported from October through March. Most were from District 9 (see Appendix K) and indicate substantial nonrecovery of spilled oil.

Table E-34. Gathering Subsystem Onshore Major Spill Events by Cause and Component

Cause	Code	Component		
		Pipe	Other	Total
Burst	14	6	0	6
Corrosion	15	21	1	22
Internal Corrosion	16	16	0	16
External Corrosion	17	7	0	7
Leak	26	2	2	4
Ported	33	4	0	4
O/M	40	3	0	3
Natural Causes	70	1	1	2
Third Party (Total)	90	12	1	13
Other		2	4	6
Total		74	9	83

E.3.6 Analysis of Total Equipment Spills for the Gathering/Distribution System

A display of total spill events reported against the Gathering/Distribution System is given in Table E-35. The system, subsystem, and equipment elements are shown with the total number of events or failures reported for each. To provide a measure of the performance of each element, Table E-35 also includes each element's percentage of contribution to the higher levels. Subsystem failures are shown as a percentage of total events reported for all systems, and total reported Gathering/Distribution System failures. Equipment failures are shown as a percentage of total events, Gathering/Distribution System events, and subsystem events.

Table E-35. Gathering/Distribution System Spill Events by Subsystem and Equipment

ELEMENT	NUMBER OF EVENTS	% TOTAL EVENTS	% SYSTEM EVENTS	% SUBSYSTEM EVENTS
Pipeline Subsystem	3226	38.23	73.03	100.00
Pipe	3117	36.87	70.44	96.44
Scraper Trap Equipment	28	0.33	0.63	0.87
Pipe Support Structure	0	–	–	–
Stream Crossing	7	0.08	0.16	0.22
Road Crossing	50	0.59	1.13	1.55
Equipment Not Identified	30	0.35	0.68	0.93
Storage Subsystem	138	1.63	3.12	100.00
Tanks	78	0.92	1.76	56.52
Tank Firewall	0	–	–	–
Tank Associated Equipment	57	0.67	1.29	41.30
Power Equipment	0	–	–	–
Equipment Not Identified	3	0.04	0.07	2.17
Pump Station Subsystem	165	1.92	3.66	100.00
Pumps	88	1.04	1.99	4.32
Centrifugal Pumps	1	0.01	0.02	0.62
Reciprocating Pumps	3	0.04	0.07	1.85
Manifold Equipment	6	0.07	0.14	3.70
Rotary Pumps	0	–	–	–
Steam Engine	0	–	–	–
Gas Turbine	0	–	–	–
Steam Turbine	0	–	–	–
Internal Combustion Engine	0	–	–	–
Electrical Motor	0	–	–	–
Pressure Controls	1	0.01	0.02	0.62
Metering Equipment	4	0.05	0.09	2.47
Valve	23	0.27	0.52	14.20
Valve Operating & Control Equipment	4	0.05	0.09	2.47
Electric Power & Control Equipment	2	0.02	0.05	1.23
Communications Equipment	0	–	–	–
Drainage System Equipment	3	0.04	0.07	1.85
Power Equipment	0	–	–	–
Equipment Not Identified	27	0.32	0.61	6.67
Safety Subsystem	3	0.02	0.05	100.00
Pressure Sensing Equipment	0	–	–	–
Pressure Switching Equipment	0	–	–	–
Flow & Gauge Equipment	1	0.01	0.02	50.00
Temperature Recorders	0	–	–	–
Power Equipment	0	–	–	–
Equipment Not Identified	1	0.01	0.02	50.00
Gathering Subsystem	870	10.29	19.66	100.00
Gravity	73	0.86	1.65	8.39
Suction	41	0.49	0.93	4.71
Pressure	8	0.09	0.18	0.92
Equipment Not Identified	748	8.85	16.90	85.98
Subsystem/Equipment Not Identified	21	0.25	0.47	N/A
Total G/D System Failures	4423	52.35	100.00	N/A
Total Failures – All Systems	8453	100.00	N/A	N/A

After extracting and displaying the system data shown in Table E-35, the most significant contributing elements were selected. Each of the equipments was ranked according to its contribution to spills. The six worst-case elements (those responsible for more than 1 percent of the system spills) were selected for further study. The equipment ranking, shown in Table E-36, lists equipment, subsystem, number of events, percentage of system, and total events. Each equipment listed in Table E-36 is discussed in the following paragraphs.

Table E-36. Ranking of Gathering/Distribution System Equipment by Number of Reported Spill Events

Equipment	Subsystem	Number of Spill Events	% of Total Events	% System Events
Pipe	Pipeline	3117	70.44	36.87
Pumps	Pump Station	88	1.99	1.04
Tanks	Storage	78	1.76	0.92
Gravity	Gathering	73	1.65	0.86
Tank Associated Equipment	Storage	57	1.29	0.67
Road Crossing	Pipeline	50	1.13	0.59

Within the Gathering/Distribution System, each of the 3117 data records for which pipe was reported was screened to identify the associated component (where applicable) and the cause. The results of the detailed analysis of these spill report records are shown in Table E-37. The table shows that the components most frequently reported for pipe equipment related spills were pipe and "not identified." The three corrosion categories combined were responsible for 1785 of the 3117 total spill events charged to pipe. Of the three corrosion categories, corroded externally was the most frequently reported cause for spills, accounting for 1083 events. The remaining causes most frequently reported were:

1. Leaking - for which the actual cause of the leak could not be determined
2. Road Machinery - such items as ditching machines, maintainers, bulldozers, and other construction and maintenance machinery

Table E-37. Pipe Equipment Spill Events by Component and Cause (3117 Reported Events)

Cause / Component		Not Reported	Broken	Burst/Ruptured	Corroded	Corroded Externally	Corroded Internally	Leaking	Road Machinery	All Other Causes Combined	Total - All Causes Combined
	Code	03	12	14	15	16	17	26	96	N/A	–
Pipe	46	116	–	126	432	1004	229	199	170	92	2368
Not Identified	00	–	13	–	22	79	19	103	18	13	285
Total		116	13	126	454	1083	248	302	188	105	2653

3. Burst/Ruptured - for failures resulting from internal pressure, presumably exceeding the capability of the component

4. Broken - for which the cause of the break could not otherwise be determined.

In addition to the component/cause relationships, there were five components for which 20 or more events were reported. They were:

1. Valves - with 24 events reported, the most frequently reported cause was burst/ruptured (four).

2. Fittings - with 24 events reported, the most frequently reported causes were sand cut (eight) and leaking (six).

3. Couplings - with 23 events reported, the most frequently reported causes were parted line or union (ten) and leaking (nine).

4. Check Valves - with 22 events reported, the most frequently reported causes were failed, opened (seven), leaking (five), and nonfunctioning (three).

5. Gasket - with 20 events reported, the most frequently reported cause was burst/ruptured (nine).

The remaining spill events assignable to pipe equipment were widely dispersed among the remaining components and causes, with no significant quantity of events reported against any single component/cause combination.

The second element on the equipment ranking list for the Gathering/Distribution System is pumps. The 88 events for this element were reviewed to determine the components and causes associated with spills reported against it. From this review, the predominant component/cause combinations were found to be:

1. Nipple - with nine events reported, the reported causes were broken (six), and road machinery (three).
2. Gland, Packing - with 11 events reported, the reported causes were leaking (five), broken (two), and four without pattern.
3. Pipe - with eight events reported, the reported causes were broken (three), corrosion (two), and three without pattern.
4. Hose - all eight events were attributed to vandalism.
5. Seals - with five events reported, the reported causes were burst/ruptured (three) and leaking (two).
6. Gasket - all four events were attributed to burst/ruptured.
7. Fasteners - all three events were attributed to broken.

The remaining 40 events reported against pump equipment were without pattern.

Tanks accounted for 78 events and is third ranked. The 78 event reports were screened and the components and causes were identified. These component/cause combinations which were reported as occurring more than once were:

1. Component Not Identified - with 36 events reported, the causes were overflowed (seven); operation incorrect (five); leaking (five); burst/ruptured (four);

corroded (four): hole (three); high wind, temperature, vandalism, corroded internally and externally (two each); and six single occurrence events.

2. Check Valve - all four events were reported as failed, open.

3. Tank Shell - with five events reported, the causes were corroded internally (two), and burst/ruptured, hole, and leaking (one each).

4. Pipe - with five events reported, the causes were corroded (two), corroded externally (two), and hole (one).

5. Valve - with four events reported, the causes were left closed (two), left open (one), and operated incorrectly (one).

The remaining reported spill events charged to tanks were single occurrence events and formed no pattern.

The total number of spill events attributed to gravity equipment was 73, making this element the fourth-ranked item. A review of these spill records disclosed that pipe accounted for 66 of the events. The causes associated with these 66 events and the number of events reported for each cause is shown in Table E-38.

Table E-38. Pipe Component (Gravity Gathering) Spill Events by Cause

Cause	Number of Spill Events
Corroded Externally	31
Corroded	11
Corroded Internally	10
Road Machinery	6
Burst	3
Farm Machinery	2
Leaking	1
Temperature	1
Third Party (Other)	1
Total	66

The seven remaining events were single occurrences of component/cause combinations involving five components and six causes.

The fifth ranked equipment element is tank associated equipment, for which 57 events were reported. A review of these disclosed that the component/cause combinations reported as occurring more than one time were:

1. Check Valve - with 23 events reported, the causes were failed opened (14), nonfunctioning (five), and four other causes (one each).
2. Valve - with 12 events reported, the causes were failed opened (three), nonfunctioning (three), and six other causes (one each).
3. Pipe - with nine events reported, the causes were leaking (two) and seven other causes (one each).
4. Control - the two events reported for this component were nonfunctioning.

The 11 remaining events were single occurrences of component/cause combinations involving eight components and ten causes.

Road crossing equipment was cited in 50 events. A review of the records showed that pipe was reported in 47 events. The causes associated with these 47 events and the number of events reported for each cause is shown in Table E-39.

Table E-39. Pipe Component (Road Crossing) Spill Events by Cause

Cause	Number of Spill Events
Road Machinery	18
Leaking	11
Corroded	8
Corroded Externally	4
Farm Machinery	3
Unknown	1
Maintenance Improper	1
Manufacturer's Defect	1
Total	47

E.4 ANALYSIS OF TOTAL COMPONENT SPILLS

This appendix has addressed component performance as it relates to system, subsystem, and equipment performance. This paragraph considers the impact of component performance on total system performance. The total data bank of 8453 spill events developed for this program contains 6791 records with component identity defined. A review of these 6791 event records disclosed that while 83 component types were identified, almost 85 percent (5719) were attributed to only eight component types. These are listed in Table E-40 in rank order based on the total number of events and the percent of contribution to the total. Each is discussed in the following paragraphs.

E.4.1 Pipe

The most frequently reported component category for all systems combined was pipe, with 4646 assigned events. Pipe also ranked first in the Gathering/Distribution System with 3506 assigned events and first in the Production System with 1135 assigned events. A review of these 4646 pipe event records revealed that eight causes collectively accounted for 3910 (84 percent) of the pipe events. Table E-41 lists these causes in rank order based on the number of assigned events. The table also shows the number of events and the percent of the total pipe events for each cause listed.

E.4.2 Valve

The component category that ranked second for all systems combined was valve, with 377 events assigned. Valve also ranked second in both the Gathering/Distribution System (77 events) and the Production System (300 events). A review of the 377 valve event records revealed that 10 causes collectively accounted for 223 (59 percent) of the valve events. Table E-42 lists these causes in rank order based on the number of assigned events and shows the number of events and the percent of the total events for each cause.

E.4.3 Dump

The third-ranked component category was dump valve, with 206 assigned events. All were reported against the Production System because this component is restricted to that system. Review of these events showed that five causes collectively accounted for 88

Table E-40. Ranking of Component Spill Events for All Systems by Component

Component	Number of Spill Events	% Total Reported Events	% Total Component Events
Pipe	4646	54.96	68.41
Valves	377	4.46	5.55
Dump Valves	206	2.44	3.03
Pumps	118	1.40	1.74
Check Valves	104	1.23	1.53
Hi Level Sensors	92	1.09	1.35
Stuffing Box	88	1.04	1.30
Coupling	72	0.85	1.06
Other	1088	12.56	15.79
Total	6791	80.34	100.00
Not Identified	1662	19.66	N/A
Total - All Events	8453	100.00	N/A

Table E-41. Ranking of Pipe Component Spill Events for All Systems by Cause

Cause	Number of Spill Events	% Pipe Events
External Corrosion	1445	31.10
Corrosion	706	15.26
Leaking	653	14.06
Internal Corrosion	361	7.77
Road Machinery	227	4.89
Burst/Ruptured	213	4.58
Hole	162	3.49
Broken	143	3.01
Other	736	15.84
Total	4646	100.00

Table E-42. Ranking of Valve Component Spill Events for All Systems by Cause

Cause	Number of Spill Events	% Valve Events
Left Open	37	9.81
Leaking	33	8.75
Failure, Closed	31	8.22
Failure, Opened	24	6.37
Nonfunctioning	24	6.37
Valve Opened/Closed	18	4.78
Vandalism	17	4.51
Broken	13	3.45
Operation Incorrect	13	3.45
Livestock	13	3.45
Other	154	40.84
Total	377	100.00

percent of the dump valve events. Table E-43 lists the causes in rank order based on the number of events and the percent of the total dump valve events for each cause.

Table E-43. Ranking of Dump Component Spill Valve Events for All Systems by Cause

Cause	Number of Spill Events	% Dump Valve Events
Failure, Closed	65	31.55
Failure, Opened	51	24.76
Nonfunctioning	28	13.59
Equipment Failure	25	12.14
Sand Cut	13	6.31
Other	24	11.65
Total	206	100.00

E.4.4 Check Valve

The fifth-ranked component category was check valve, with 104 assigned events. It ranked third in the Gathering/Distribution System, but with 36 assigned events, it was not included in the ranking table for the Production System. Review of these events shows that five causes accounted for 71 percent of the check valve events. Table E-44 lists the causes in rank order based on the number of assigned events and shows the number of events and the percent of the total events for each cause.

Table E-44. Ranking of Check Valve Component Spill Events for All Systems by Cause

Cause	Number of Spill Events	% Check Valve Events
Failure, Opened	36	34.62
Leaking	15	14.42
Nonfunctioning	14	13.46
Failure, Closed	5	4.81
Burst/Ruptured	4	3.85
Other	30	28.84
Total	104	100.00

E.4.5 Hi Level Sensor

The sixth-ranked component category was hi level sensor with 92 assigned events. It was fifth-ranked in the Production System and no events were charged to the Gathering/Distribution System. Review of these events shows that one cause (nonfunctioning) was responsible for 58 or 63 percent of the events.

E.4.6 Stuffing Box

The seventh-ranked component category was stuffing box with 88 assigned events. It ranked sixth in the Production System with all events occurring within that system due to application limitations. Review of these events shows that seven causes collectively accounted for 89 percent of the events. Table E-45 lists the causes in rank order based on the number of assigned events and shows the number of events and the percent of the total events for each cause.

Table E-45. Ranking of Stuffing Box Component Spill Events for All Systems by Cause

Cause	Number of Spill Events	% Stuffing Box Events
Leaking	30	34.09
Equipment Failure	13	14.77
Improper Maintenance	11	12.50
Overpressure	9	10.23
Burst/Ruptured	8	9.10
Plugged	4	4.55
Worn	3	3.41
Other	10	11.35
Total	88	100.00

E.4.7 Coupling

The eighth-ranked component category was coupling, with 72 assigned events. It ranked fifth in the Gathering/Distribution System with 36 assigned events but was not included in the ranking table for the Production System.

Review of these events revealed that seven causes collectively accounted for 61 (85 percent) of the events. Table E-46 lists these causes in rank order based on the number of assigned events and shows the number of events and the percent of the total events for each cause.

Table E-46. Ranking of Coupling Component Spill Events for All Systems by Cause

Cause	Number of Spill Events	% Coupling Events
Leaking	22	30.55
Line or Union Parted	18	25.00
Temperature	6	8.33
Broken	4	5.56
Burst/Ruptured	4	5.56
Assembled Improperly	4	5.56
Material Defect	3	4.17
Other	11	15.27
Total	72	100.00

E.5 ANALYSIS OF SPILL QUANTITY

E.5.1 Overview of Spill Quantity Data

Tables D-27 through D-29 in Appendix D present spill quantity categories versus the responsible component. The spill quantities are categorized into major, moderate, and minor spills. A minor spill is less than 2.4 barrels (100 gallons), a moderate spill is from 2.4 to 238 barrels (100 to 10,000 gallons) and a major spill is 238 barrels (10,000 gallons) or more. The distribution of total spill events by system and size of spill is given in Table E-47.

Table E-47. Summary of Reported Spill Events by System and Spill Category

System	Minor	Moderate	Major	Quantity Not Determined	Total
Drilling	7	10	4	16	37
Gathering/Distribution	70	3456	794	103	4423
Production	585	2673	215	520	3993
Total	662	6139	1013	639	8453
% of Total	7.8	72.6	12.0	7.6	100.0

Table E-47 shows that the moderate category accounts for the largest number and the minor category accounts for the smallest number. Events occurring within these spill categories are discussed for each system in the following paragraphs.

E.5.2 Drilling System

There were 37 spill events reported against the Drilling System, representing 0.44 percent of the total spills for all systems, of which 16, representing 43.2 percent of the total Drilling System spills, could not be related to a quantity size. Table E-48 presents a summary of the spill quantity quantification for the Drilling System.

Table E-48. Summary of Drilling System Spill Events by Spill Category

Spill Category	Number of Spill Events	% of Total
Minor	7	18.9
Moderate	10	27.0
Major	4	10.8
Not determined	16	43.3
Total	37	100.0

There were four major spill events reported against the Drilling System, representing 10.8 percent of the total system spills. No trends of significance were exhibited.

There were ten moderate spill events reported against the Drilling System, representing 27 percent of the total system spills. Only one component associated with these spills (choke) was identified.

There were seven minor spill events reported for the Drilling System, representing 18.9 percent of the total system spills. No trends were exhibited. As shown in Table E-49, the spill events were distributed among a few components with no component having a significant percentage of the total.

Table E-49. Drilling System, Minor Spill Events by Component

Component	Number of Minor Spill Events	% of Total
Not Identified	3	42.8
Pipe	2	28.6
Rupture-Disc	1	14.3
Control	1	14.3
Total	7	100.0

E.5.3 Production System

There were 3993 spill events reported against the Production System representing 47.2 percent of the total spills. The distribution of Production System spill events by spill category is given in Table E-50. There were 520 spills from Production Systems whose spill category could not be determined accounting for 13 percent of the total system spills. Each spill category is discussed in the following paragraphs.

Table E-50. Production System Spill Events by Spill Category

Spill Category	No. of Spill Events	% of Total
Minor	585	14.7
Moderate	2673	66.9
Major	215	5.4
Not determined	520	13.0
Total	3993	100.0

There were 215 major spill events reported in the Production System representing 5.4 percent of the total system spills. Table E-51 presents the components responsible for the majority. Of the identified components, pipe and valves were the largest contributors. The remaining spills were distributed among several components.

Table E-51. Production System Major Spill Events by Component

Component	Number of Major Spill Events	% of Total
Not Identified	78	36.3
Pipe	47	21.9
Valve	35	16.3
Dump Valve	12	5.6
Other	43	19.9
Total	215	100.0

There were 2673 moderate spill events reported against the Production System representing 66.9 percent of the total spills. Table E-52 shows the components responsible for the majority of the spills. The identified components responsible were pipe and valves.

Table E-52. Production System Moderate Spill Events by Component

Component	Number of Moderate Spill Events	% of Total
Pipe	920	34.4
Not Identified	657	24.6
Valve	218	8.2
Dump Valve	150	5.6
Other	728	28.2
Total	2673	100.0

There were 585 minor spill events reported in the Production System representing 14.7 percent of the total. Table E-53 presents the components associated with the majority. Of the identified components, pipe and valves account for the largest contributors.

Table E-53. Production System Minor Spill Events by Component

Component	Number of Minor Spill Events	% of Total
Not Identified	178	30.4
Pipe	95	16.2
Dump Valve	54	9.2
Hi Level Sensor	30	5.1
Valve	24	4.1
Pressure Relief Valve	24	4.1
Other	180	30.9
Total	585	100.0

E.5.4 Gathering/Distribution System

The Gathering/Distribution System had 4423 spill events reported, representing 52.3 percent of the total spills for all systems. A total of 103 spills, representing 2.3 percent of the system total, could not be related to a quantity size. Table E-54 presents a summary of the spill quantity quantification for the Gathering/Distribution System.

Table E-54. Gathering/Distribution System Spill Events by Spill Category

Spill Category	Number of Spill Events	% of Total
Minor	70	1.6
Moderate	3456	78.1
Major	794	17.9
Not Determined	103	2.4
Total	4423	100.0

There were 794 major spill events reported for the Gathering/Distribution System representing 17.9 percent of the total spills. Table E-55 shows the components responsible for the majority. Pipe had 608 events attributed to it. Valves and welds were the second and third largest contributors. The remainder were distributed among other components.

Table E-55. Gathering/Distribution System Major Spill Events by Component

Component	Number of Major Spill Events	% of Total
Pipe	608	76.6
Not Identified	70	8.8
Valves	20	2.5
Welds	17	2.1
Other	79	10.0
Total	794	100.0

There were 3456 moderate spill events reported in the Gathering/Distribution System representing 78.1 percent of the total spills. Table E-56 shows the components responsible for the largest number. Pipe was involved most with 2787, or 80.6 percent of the system total. Valves were next. The three types of valves accounted for 148 spills or 4.3 percent of the total.

Table E-56. Gathering/Distribution System Moderate Spill Events by Component

Component	Number of Moderate Spill Events	% of Total
Pipe	2787	80.6
Not Identified	302	8.7
Check Valves	66	1.9
Valves	54	1.6
Gate Valve	28	0.8
Other	219	6.4
Total	3456	100.0

In the Gathering/Distribution System there were 70 minor spill events reported representing 1.6 percent of the total. Table E-57 shows those components responsible for the largest number of spills. Pipe was responsible for 47 spills, or 67 percent. Those spills for which the data sources did not specify a responsible component are classified as "not identified." The remaining spills are distributed among the other components.

Table E-57. Gathering/Distribution System Minor Spill Events by Component

Component	Number of Minor Spill Events	% of Total
Pipe	47	67.1
Not Identified	8	11.4
Pump	4	5.7
Other	11	15.8
Total	70	100.0

E.5.5 Analysis of Major Spill Events

The major spill category was investigated to determine if any unique components or causes could be found that specifically caused major spills. As a first step, Table D-25, in Appendix D, was generated. This table shows equipment versus cause for each major spill. There were 1013 major spills reported. Table E-58 presents a ranking of the major causes and equipments associated with the major spills. This table contains 640 of the 1013 spill events ranked according to the equipment having the most incidents of spills. In this table, 109 spill events were reported due to a third party. Those attributed to road machinery (71) and farm machinery (14) are shown separately. All other reported third party causes account for the remaining 24 events.

Referring to Table E-58, pipe was associated with 496 major spills, representing 48.9 percent. Corrosion was the most prevalent cause of these pipe failures, accounting for 260 spill events or 52.4 percent of the pipeline spills. The second most frequent equipment associated with spills was tanks, with 41 major spills, representing 4.1 percent of the total. The most frequent cause of tank equipment spills was hole, 41.5 percent. The gathering pipeline subsystem accounted for 3.9 percent of the total spills. The major cause for spills relative to this equipment was corrosion, accounting for 31 spills or 77.5 percent of the total gathering pipeline subsystem major spills.

Table E-58. Ranking of Reported Component Major Spill Events by Cause and Equipment

Cause	Code	11100 Pipe	15000 Gathering Pipeline Subsystem	11500 Road Crossing	13100 Pump	36100 Tanks	33100 Flow Line Equipment	35100 Heater Treater	Total
Externally Corroded	16	162	11						173
Road Machinery	96	71		8					79
Internally Corroded	17	54	5						59
Corroded	15	44	15	5					64
Burst/Ruptured/Split	14	40	5		4	8	5		62
Material Defective	20	30							30
Defective Weld	39	27							27
Third Party (Other)	90	24							24
Leaking	26	16	4			8	8		36
Parted Line or Union	33	14					4		18
Farm Machinery	93	14							14
Broken	12				3		6		9
Plugged	34				3				3
Hole	25					17	5	3	25
Overflowed	31					4			4
High wind	81					4			4
Equipment Failure	10							6	6
Failure Opened	22							3	3
Total		496	40	13	10	41	28	12	640

E.6 ANALYSIS OF REPORTED SPILL CAUSES

The causes tabulated from the data were divided into the following six categories.

1. Unknown - data did not reveal the cause of the event.
2. Equipment Failure - event was a result of hardware failure.
3. Operator/Maintenance Error - event was caused by an equipment operator or maintenance personnel.
4. Engineering Error - events caused by faulty or improper design, application, or layout of the equipment.
5. Natural Causes - events attributed to environmental conditions.
6. Third Party - outside sources.

Table E-59 shows the number of spill events per system for each cause category. Equipment failure represented the largest percentage (81.1 percent) of spill events for all systems. Of the 3709 spill events for the Gathering/Distribution System attributable to equipment failure, 2511 (67.7 percent) were caused by corrosion. Causes such as burst, hole, and leaking, any of which could be a result of corrosion, accounted for 715 events. Of the 408 third party events, 254 (62.3 percent) resulted from road machinery. In the Gathering/Distribution System, equipment failure represented 83.9 percent and third party 9.2 percent. Of the 3993 events for the Production System, 3138 (78.6 percent) were reported as equipment failure. The most frequent cause was leaking, with 766 (24.4 percent). The combination of corrosion, hole, and burst accounted for 669 (21.3 percent). A large percentage of leaking, hole, and burst causes may have been the result of corrosion.

Table E-59. Spill Events by Cause Category and System

Cause Category	Code	Drilling System	% of System	Production System	% of System	Gathering/ Distribution System	% of System	Totals	% of Totals
Unknown	01-04	10	27.03	261	6.50	194	4.39	465	5.50
Equipment Failure	10-39-A1	10	27.03	3138	78.67	3709	83.86	6857	81.12
Operator/Maintenance Error	40-55	6	16.22	293	7.30	71	1.60	370	4.38
Engineering Error	60-64	2	5.40	12	0.30	2	0.05	16	0.19
Natural Causes	70-83	9	24.32	161	4.03	39	0.88	209	2.47
Third Party	90-99	0	—	128	3.20	408	9.22	536	6.34
TOTAL		37	100.0	3993	100.0	4423	100.0	8453	100.0

APPENDIX F

FAILURE MODES AND EFFECTS ANALYSIS (FMEA)

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APPENDIX F

FAILURE MODES AND EFFECTS ANALYSIS (FMEA)

F.1 INTRODUCTORY SUMMARY

These analyses are important to the spill prevention program described in this report since they provide an analytical framework to cover any specific facility and to allow consistent comparative analysis. They draw upon the configuration information obtained during the field surveys (see Appendix A) and the oil spill data tabulated in Appendix D and analyzed in Appendix E and Volume I. The importance of FMEA to this study, in addition to aiding the development of the basic systems description in Appendix B, is in the derivation of spill prevention guidelines presented in Volume I. This appendix is included to substantiate the spill prevention guidelines of Volume I, and to provide a theoretical basis for stimulating new applications of these powerful methods to the prevention of oil spills.

F.2 FMEA METHODOLOGY AND SELECTION CRITERIA

In this study, failure is defined to be a spillage of crude oil or condensate. The principal objective of FMEA is to identify all failure modes of a system and, through analysis, determine which modes are significant causes of failure (as defined). Two basic approaches may be used: the first, or classical approach, is an inductive process that starts at the lowest level (part) of the system and evaluates the effect of each part failure mode on the next and successively higher levels of the system until the effect on system performance is established. The second, or hazard analysis approach, is a deductive process that starts with defined hazards at the system level and examines possible failure conditions at the next and progressively lower levels of the system until the failure modes that allow the hazard to exist are determined. The latter approach is used in this study.

The term "hazard" is defined here as a condition (or state) which contributes to the occurrence of a failure. For this study, the hazards to be analyzed are limited only to those which contribute to oil or condensate spillage. Hazards which contribute to personnel injury or death, equipment or property damage, or loss of product are not addressed by this study unless they also contribute to oil or condensate spillage.

The Hazards Analysis is performed using the methodology of Fault Tree Analysis (FTA). Advantages of the FTA approach include the following:

- The FTA approach specifically accommodates only those elements contributing to the particular oil spill under study. Failures that do not contribute to an oil spill are not included.
- The documentation on parts, components, and equipments used in the petroleum systems studied does not readily lend itself to an inductive analysis from the lowest levels to the succeedingly higher levels.
- The "top down" approach readily identifies human and externally induced failure modes which can result in an oil spill.

In this study, the FTA has been developed to assist in establishing the cause and effect relationship between system oil spills and lower system element failure modes. The analyses have had significant value in identifying items which are potentially spill vulnerable, an essential, preparatory step in deriving the spill prevention guidelines presented in Volume I .

F.3 FAULT TREE ANALYSIS APPROACH

A total FTA methodology may be approached through six basic steps. Steps 1 through 4 have been developed for immediate implementation. Steps 5 and 6 require additional data elements and analysis before they can be implemented. Preliminary concepts of these steps have been considered and the initial content of each step follows:

1. Step 1: Identify and define equipment associated with the facility (system) being analyzed. Volume I presents a generalized configuration based on functional categorization of the equipments. The specific equipment identification will be derived from the technical data package.

2. Step 2: Develop functional flow diagrams for the facility being analyzed, with progressively detailed diagrams at lower tier levels. This will provide an understanding of the functional operation of the facility and associated subsystems. The diagrams presented in Appendix A are examples of simplified functional flow diagrams of facilities visited. Similar, but more detailed, diagrams will be included in, or could be constructed from, the technical data package provided.

3. Step 3: Develop fault tree diagrams for potential occurrence of spill events for each crude oil system addressed in the study through analysis of the functional flow diagrams supplemented by analysis of specific equipment and components in suppliers' catalogs. These diagrams are presented in the following paragraphs. The symbols for understanding the fault tree diagrams are defined in Table F-1. They are standard digital logic symbols that relate the causative elements to the events of interest.

4. Step 4: Refine fault tree diagrams in accordance with additional causative elements that result from analysis of the spill data in Appendix E.

5. Step 5: Develop equations describing the fault tree diagrams through application of probability theory. The probabilistic equations required for the various logic steps in the diagrams are presented in the following paragraphs.

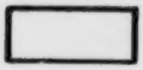
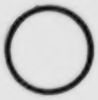
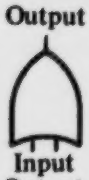
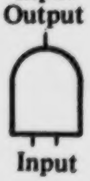
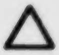
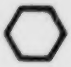
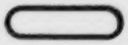
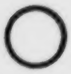
   - The probability, P(A), that a specific hazard will occur as the result of one or more causative malfunctions or fault events (B_i) occurring (EITHER-OR situation) is:

$$P(A) = 1 - \prod_{i=1}^{n} Q(B_i)$$

where:

$$\prod_{i=1}^{n} Q(B_i) = Q(B_1) \times Q(B_2) \times \ldots\ldots \times Q(B_n)$$

Table F-1. Definitions of Symbols Used in Fault Tree Diagrams

Logic Symbol	Definition
	An event, usually a malfunction, that results from one or a combination of other events and is describable in functional terms. Examples are blowouts, kicks, and other generally described occurrences.
	A basic event, or lowest identifiable condition or fault. Examples are pore pressures, valve cutout, or valve left open.
	EITHER-OR, a situation whereby an output will exist if any or all of the input events are presented. An example is a relay valve will fail if EITHER there is a valve stem seal leak OR the valve spring is hung up OR both occur.
	AND, the coexistence of all input events are required to produce the output event.
	Transfer symbol - connecting to a more detailed diagram.
	CONDITIONAL that another event has occurred or that the named circumstances exist at the time of the event of interest. For example, a high level sensor failure can only result in an overflow on the condition that another failure has occurred.
	The CONDITIONAL event of interest.
	Specific activity involved.

and P(A) is the probability of occurrence of the specific hazard event of interest, $Q(B_i)$ is the probability that the causative malfunction or fault (B_i) will not occur and equals $1 - P(B_i)$, $P(B_i)$ is the probability that the causative malfunction or fault (B_i) will occur, and n is the number of fault conditions that contribute to a specific hazard.

- The probability, P(A), that a specific hazard event will occur as the result of all causative malfunctions or faults occurring (AND situation):

$$P(A) = \prod_{i=1}^{n} P(B_i)$$

- The probability that a hazard will occur upon the condition that another stimulating event has occurred (CONDITIONAL situation):

$$P(A) = P(B_i)\, P(A|B_i)$$

  The equation is read as follows:

  > The probability that event A will occur is equal to the probability that the events B_i will occur times the probability that event A will occur on the condition that B_i has already occurred.

6. Step 6: Determination of a Spillage Impact Factor (SIF) is desirable to modify, or weight, the impact of the probability of malfunction which defines how often a spill occurs (Step 5) by injecting consideration of the average quantity of crude oil a specific failure can be expected to spill. Thereby, a more complete estimate can be made with respect to the overall impact of a specific failure. In this manner, comparisons can be derived that indicate whether a particular component that fails frequently, but spills small amounts of oil, has more or less impact than another component that fails less frequently but spills more oil. Throughout this study this modifier will be called a Spillage Impact Factor (SIF). To derive the SIF, the average quantity of oil spillage for each component failure was determined. This value was modified

by a multiplier based on the highest average spill component. The SIF scale was therefore made to range from 1 to 1000.

Steps 1 through 4 had utility in deriving the spill prevention guidelines presented in Volume II. Steps 5 and 6 have future utility for:

1. Ranking the overall spill impact of various malfunction events after multiplying the SIF of the malfunction event of interest by the probability that the malfunction will occur, i.e., a criticality ranking.
2. Comparing configurations at various levels to allow tradeoff considerations to attain an optimum criticality-ranked configuration.

Achieving the benefits of ranking and tradeoff through use of Steps 5 and 6 will require:

1. Developing data to derive statistical failure distributions and calculate numerical values of terms used by probability equations in Step 5.
2. Developing equations for using and calculating SIFs at various logic steps in the fault tree diagrams.

F.4 SYSTEM LEVEL FTA

The system level fault tree diagram, Figure F-1, shows the ability of this analytical method to address any system, and depicts the top tier for crude oil systems. It is a generalized presentation relating any crude oil spillage event to one of the major functional phases of crude oil processes. The system level diagram is readily expandable to include product spillage from other system functions within the petroleum life cycle. Detailed fault tree diagrams for system major functional phases in this study and the phase description are presented in later paragraphs. Note that the Emergency Safety Shutdown in Production and Gathering/Distribution Systems can contribute to a spill only if an associated subsystem has previously failed. The Production subsystems identified for more detailed FTA were chosen because they are more frequent contributors to oil spillage, as indicated in Volume I . The resulting conclusions drawn from these subsystems are translatable to the Gathering/Distribution System.

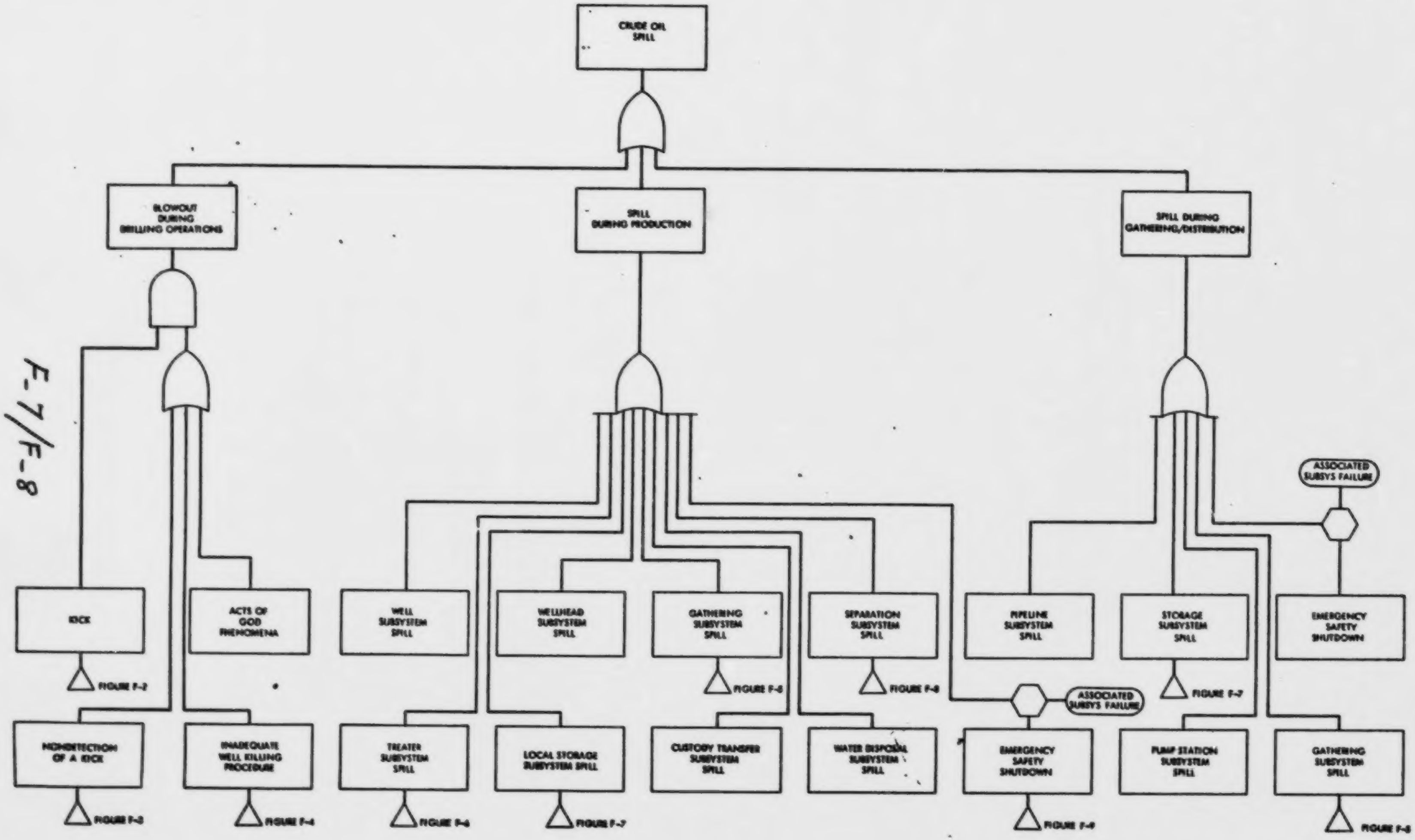

CRUDE OIL SPILL
BLOWOUT DURING DRILLING OPERATIONS
SPILL DURING PRODUCTION
SPILL DURING GATHERING/DISTRIBUTION
KICK
FIGURE F-2
ACTS OF GOD PHENOMENA
NONDETECTION OF A KICK
FIGURE F-3
INADEQUATE WELL KILLING PROCEDURE
FIGURE F-4
WELL SUBSYSTEM SPILL
WELLHEAD SUBSYSTEM SPILL
GATHERING SUBSYSTEM SPILL
FIGURE F-8
SEPARATION SUBSYSTEM SPILL
FIGURE F-8
TREATER SUBSYSTEM SPILL
FIGURE F-6
LOCAL STORAGE SUBSYSTEM SPILL
FIGURE F-7
CUSTODY TRANSFER SUBSYSTEM SPILL
WATER DISPOSAL SUBSYSTEM SPILL
ASSOCIATED SUBSYS FAILURE
EMERGENCY SAFETY SHUTDOWN
FIGURE F-9
PIPELINE SUBSYSTEM SPILL
STORAGE SUBSYSTEM SPILL
FIGURE F-7
ASSOCIATED SUBSYS FAILURE
EMERGENCY SAFETY SHUTDOWN
PUMP STATION SUBSYSTEM SPILL
GATHERING SUBSYSTEM SPILL
FIGURE F-8

Figure F-1. System Level Fault Tree Diagram for the Various Crude Oil Systems

F.5 DRILLING SYSTEM FTA

The most significant oil spillage event that can occur during the drilling phase of the crude oil process is a blowout. The fault tree diagrams for the components of a potential blowout event are presented in Figures F-2 through F-4. A study of these diagrams and the blowout event portion of the system level fault tree diagram (Figure F-1) identifies the branches and, ultimately, the roots of the fault tree. These roots represent the conditions, activities, and failure modes that, collectively or individually, are prerequisite to a blowout. The four main branches of causative conditions and activities relative to a blowout are (1) the occurrence of a kick (i.e., the unexpected flow of formation fluid into the well bore), (2) not detecting that the kick had occurred, (3) improperly killing the well, or (4) an act of God phenomena preventing proper well control action from being taken. In other words, these categories address failure to dominate reservoir pressure, failure to recognize that the domination of the reservoir pressure had been lost, or failure to recapture domination over the reservoir pressure. Eventually, as shown in Figures F-2 through F-4, the roots of the tree are reached; that is, the detailed level is attained which allows consideration of improvement in activities and equipments that may alleviate the potential of a blowout.

The ultimate roots in Figures F-1 through F-4 indicate that causative events (such as acts of God, weak formations, abnormal pressures, the formation characteristics conducive to developing a kick) cannot be eliminated. However, their resulting effects can be alleviated by careful planning, prudent operations, and adequate equipment. Areas which are candidates for improvement include 16 geological/engineering elements, 21 operational elements, and 17 general equipment elements. Three of the geological/engineering elements supply assistance through procedures and training to improve operating personnel skills in maintaining pressure control. It becomes evident that the human element presents a significant factor in blowout prevention.

Table F-2 presents a qualitative example of an FMEA performed on selected equipments. The cause and effect relationships can be established at successively lower levels and FMEAs performed at component and part levels. If appropriate data are obtained, FMEAs measurable in terms of probability of failure can be performed at system, subsystem, equipment, component, and even part level. However, adequate quantities of appropriate data will, at best, be difficult to obtain.

The data obtained did not contain sufficient information for the determination of blowout-associated failure modes. As indicated in Table D-19, in Appendix D, of the 37 reported crude oil spillage events that occurred during the drilling function, only eight were identifiable as to cause. The time frame during which these blowouts occurred is estimated to be several years. It is not known how many other blowouts occurred and were not reported. However, this number could not be large. During recent years, drilling rig activity has averaged over one thousand, and there are also several hundred work-over rigs still active.

The 37 reported spillage events were not all associated with blowouts. Consequently, the impact of the various failure modes shown in the FTA upon blowouts could not be quantified from these data. However, useful information was obtained through a selective literature review (References 1, 2, and 3), and assistance from a Petroleum Engineering Consultant possessing considerable drilling expertise. Another publication (Reference 4) was of particular value in assessing the relative contribution of various drilling operations to the occurrence of blowouts. An abbreviated table from Reference 4, supplemented with data obtained during the present study from eight additional blowouts, is presented in Table F-3. These data permitted a tabulation (Table F-4) of activity being performed, by location, at the time of blowout. This tabulation indicates that 92.5 percent of the blowout events considered occurred during tripping or drilling. The same data also permitted a tabulation (Table F-5) of the type of fluid involved in the blowout. As shown by well location, gas flow accounted for more than half of the blowouts considered. Limited information on the results of pressure testing of ram-type blowout preventers was also obtained and is presented in Table F-6. As indicated by the initial tests in the table, of the 1000 preventer stacks and manifolding that were pressure tested on initial installation in the field, 194 leaks were detected at the five areas listed. Thus, maintaining a pressure seal is a problem on blowout preventers even prior to withstanding the

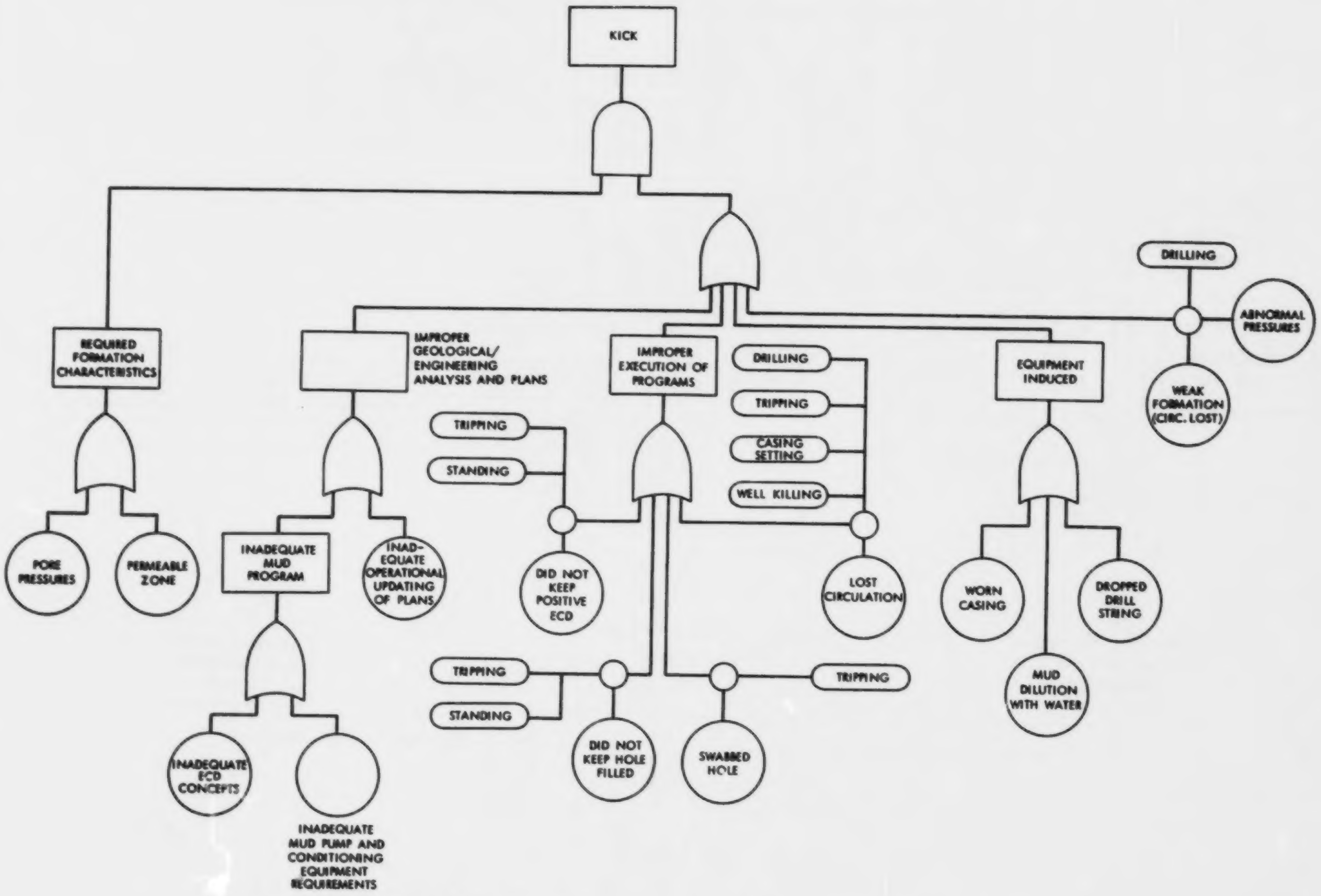

KICK
REQUIRED FORMATION CHARACTERISTICS
PORE PRESSURES
PERMEABLE ZONE
IMPROPER GEOLOGICAL/ ENGINEERING ANALYSIS AND PLANS
INADEQUATE MUD PROGRAM
INAD-EQUATE OPERATIONAL UPDATING OF PLANS
INADEQUATE ECD CONCEPTS
INADEQUATE MUD PUMP AND CONDITIONING EQUIPMENT REQUIREMENTS
IMPROPER EXECUTION OF PROGRAMS
TRIPPING
STANDING
DID NOT KEEP POSITIVE ECD
TRIPPING
STANDING
DID NOT KEEP HOLE FILLED
SWABBED HOLE
TRIPPING
DRILLING
TRIPPING
CASING SETTING
WELL KILLING
LOST CIRCULATION
EQUIPMENT INDUCED
WORN CASING
MUD DILUTION WITH WATER
DROPPED DRILL STRING
DRILLING
ABNORMAL PRESSURES
WEAK FORMATION (CIRC. LOST)

Figure F-2. Fault Tree Diagram for the Development of a Kick (Drilling and Completion Operations)

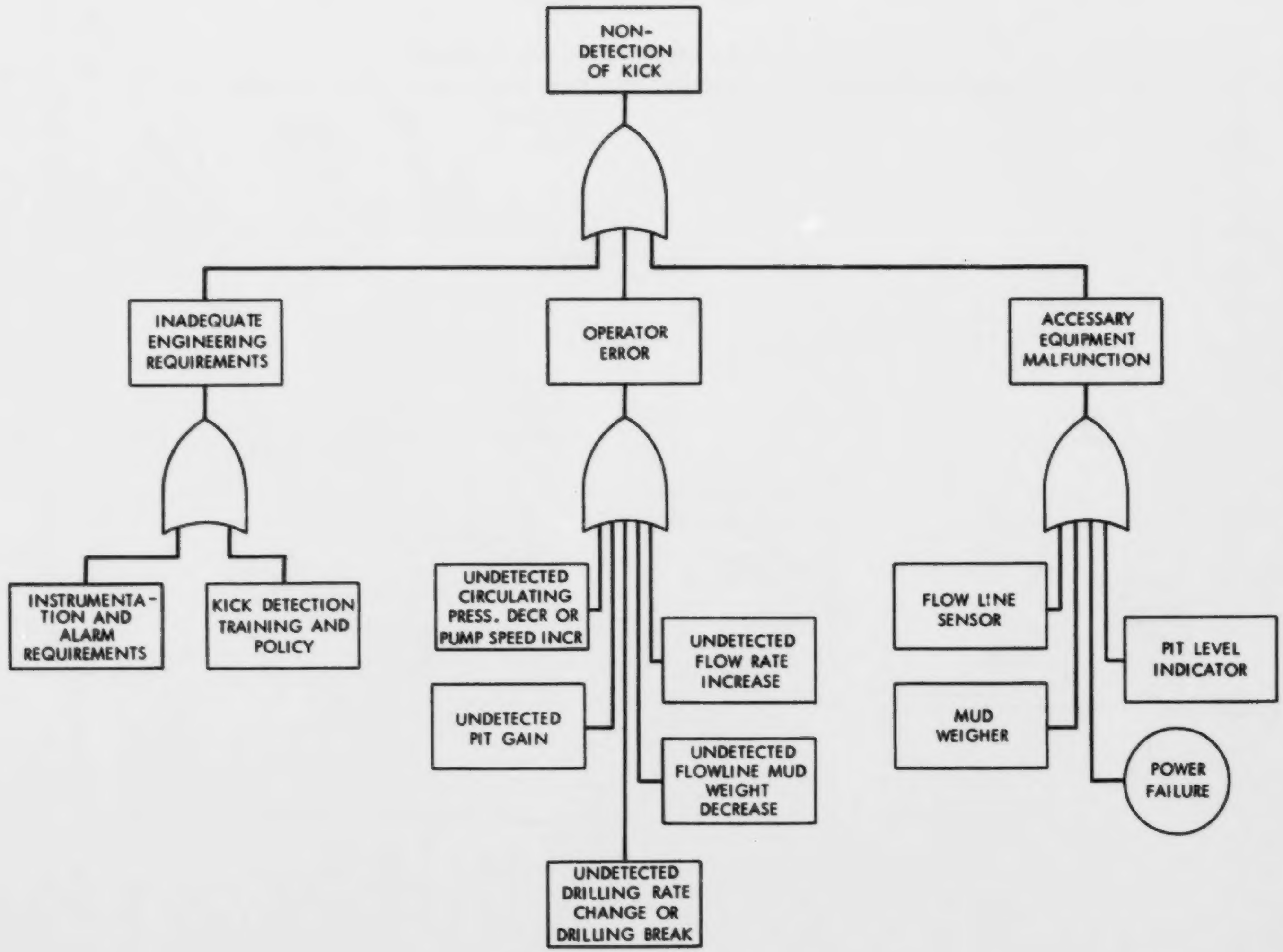

NON-DETECTION OF KICK
INADEQUATE ENGINEERING REQUIREMENTS
OPERATOR ERROR
ACCESSARY EQUIPMENT MALFUNCTION
INSTRUMENTA-TION AND ALARM REQUIREMENTS
KICK DETECTION TRAINING AND POLICY
UNDETECTED CIRCULATING PRESS. DECR OR PUMP SPEED INCR
UNDETECTED PIT GAIN
UNDETECTED FLOW RATE INCREASE
UNDETECTED FLOWLINE MUD WEIGHT DECREASE
UNDETECTED DRILLING RATE CHANGE OR DRILLING BREAK
FLOW LINE SENSOR
MUD WEIGHER
PIT LEVEL INDICATOR
POWER FAILURE

Figure F-3. Fault Tree Diagram for Nondetection of a Kick (Drilling and Completion Operations)

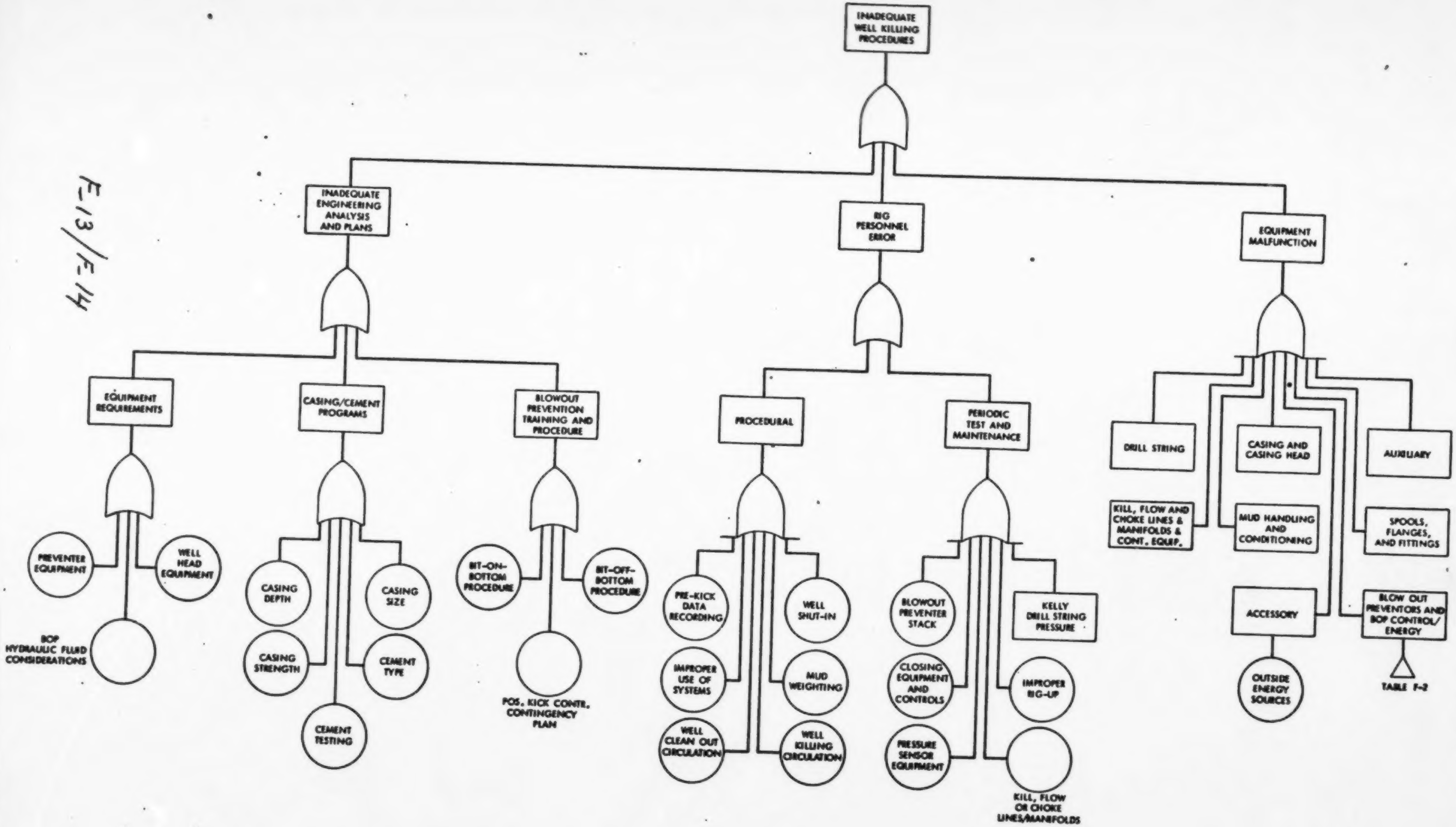

INADEQUATE WELL KILLING PROCEDURES
INADEQUATE ENGINEERING ANALYSIS AND PLANS
RIG PERSONNEL ERROR
EQUIPMENT MALFUNCTION
EQUIPMENT REQUIREMENTS
CASING/CEMENT PROGRAMS
BLOWOUT PREVENTION TRAINING AND PROCEDURE
PROCEDURAL
PERIODIC TEST AND MAINTENANCE
DRILL STRING
CASING AND CASING HEAD
AUXILIARY
KILL, FLOW AND CHOKE LINES & MANIFOLDS & CONT. EQUIP.
MUD HANDLING AND CONDITIONING
SPOOLS, FLANGES, AND FITTINGS
ACCESSORY
BLOW OUT PREVENTORS AND BOP CONTROL/ENERGY
OUTSIDE ENERGY SOURCES
TABLE F-2
PREVENTER EQUIPMENT
WELL HEAD EQUIPMENT
BOP HYDRAULIC FLUID CONSIDERATIONS
CASING DEPTH
CASING SIZE
CASING STRENGTH
CEMENT TYPE
CEMENT TESTING
BIT-ON-BOTTOM PROCEDURE
BIT-OFF-BOTTOM PROCEDURE
POS. KICK CONTR. CONTINGENCY PLAN
PRE-KICK DATA RECORDING
WELL SHUT-IN
IMPROPER USE OF SYSTEMS
MUD WEIGHTING
WELL CLEAN OUT CIRCULATION
WELL KILLING CIRCULATION
BLOWOUT PREVENTER STACK
KELLY DRILL STRING PRESSURE
CLOSING EQUIPMENT AND CONTROLS
IMPROPER RIG-UP
PRESSURE SENSOR EQUIPMENT
KILL, FLOW OR CHOKE LINES/MANIFOLDS

Figure F-4. Fault Tree Diagram for Inadequate Well Killing Control (Drilling and Completion Operations)

Table F-2.
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EQUIPMENT OR ACTIVITY	ITEM	FUNCTION	CRITICAL SYSTEM EFFECT	COMMENTS	UNDESIRABLE CONDITION OR FAILURE TYPE
ANNULAR BLOWOUT PREVENTER (BOP)	PACKING UNIT	PROVIDES PRESSURE SEAL AROUND PIPE, TOOL JOINTS, KELLY, OR OVER OPEN HOLE	DAMAGED OR WORN FROM PRIOR USE	USELESSNESS OF BOP DURING BLOWOUT ACTIVITY IN SEALING ANNULUS	COULD BE CATASTROPHIC
	PACKING UNIT	SAME AS ABOVE	DAMAGE TO PACKING UNIT BY OIL BASE MUD IF NATURAL RUBBER IS USED INSTEAD OF SYNTHETIC RUBBER	SAME AS ABOVE	COULD BE CATASTROPHIC
	PACKING UNIT	SAME AS ABOVE	WRONG PACKER MATERIAL USED FOR COLD TEMPERATURES. DAMAGE TO NATURAL RUBBER PACKING UNIT BY COLD TEMPERATURES (LESS THAN 20°F)	POSSIBLE EMBRITTLEMENT IMPAIRS PACKER ABILITY TO WITHSTAND PRESSURE SHOCK. NEOPRENE RUBBER PACKING UNIT REQUIRED FOR TEMP. LESS THAN 20°F	
	UPPER CONTRACTOR PISTON SEAL RING	SEALS BETWEEN HEAD AND CONTRACTOR PISTON TO PROVIDE PRESSURE SEAL FOR TOP CHAMBER	SEALING EDGE WORN OR ROUGH	PRESSURE SEAL LESS IN THE TOP CHAMBER RESULTS IN AN INABILITY TO OPEN THE BOP	NOT CATASTROPHIC
	HEAD GASKET	SEALS BETWEEN HEAD AND BODY TO PROVIDE PRESSURE SEAL FOR TOP CHAMBER	SAME AS ABOVE	SAME AS ABOVE	SAME AS ABOVE
	CONTRACTOR PISTON HEAD SEAL RING	PROVIDES PRESSURE SEAL BETWEEN TOP AND BOTTOM CHAMBERS	SAME AS ABOVE	RETARDS BOP CLOSURE AND POSSIBLY PREVENTS CLOSURE ALTOGETHER	COULD BE CATASTROPHIC
	LOWER CONTRACTOR PISTON SEAL RING	SEALS BETWEEN PISTON AND BODY TO PROVIDE PRESSURE SEAL FOR LOWER CHAMBER	SAME AS ABOVE	ALLOWS WELL PRESSURE TO ENTER INTO THE CONTROL SYSTEM	COULD BE CATASTROPHIC
PIPE AND BLIND RAM BOP	RAM PACKER	PROVIDES PRESSURE SEAL AROUND PIPE AND/OR ON MATING FACES OF RAMS	DAMAGED OR WORN	BOP COULD BE INEFFECTIVE IN SEALING ANNULUS DURING BLOWOUT	COULD BE CATASTROPHIC
	TOP RAM SEAL	PROVIDES PRESSURE SEAL BETWEEN BODY AND RAM	DAMAGED OR WORN	ALLOWS WELL PRESSURE USED TO ASSIST RAM CLOSING TO LEAK AND RESULTS IN LOSS SEAL	COULD BE CATASTROPHIC
	RAM TAIL ROD SEALS	TO PROVIDE A PRESSURE SEAL RAM TAIL ROD AND BONNET	HYDRAULIC FLUID LEAK BETWEEN CLOSING PASSAGE AND LOCKING SCREEN HOUSING	COULD RETARD, BUT NOT MAKE ENTIRELY INEFFECTIVE, THE CLOSING ACTION OF PISTONS. WELL PRESSURE EQUALIZED BETWEEN BORE AND BEHIND RAM WOULD NOT ASSIST, BUT NOT HINDER EITHER.	NOT CATASTROPHIC BOTH SEALS, THE WIPING "O" RING AND THE TAIL ROD SEAL RING, WOULD HAVE TO FAIL.
	BONNET OR DOOR SEALS	TO PROVIDE PRESSURE SEAL BETWEEN THE BONNET, OR DOOR, AND THE BODY AND PROVIDE SEAL BETWEEN BONNET BOLTS AND BONNET	WELL PRESSURE LEAK AT INTERFACE BETWEEN PREVENTER BODY AND INTERMEDIATE FLANGE	LOSS OF SEAL, FLOW, OR SAND CUTTING OUT DURING BLOWOUT	COULD BE CATASTROPHIC
	OPERATING PISTON 'O' RING	TO PROVIDE PRESSURE SEAL BETWEEN THE OPERATING PISTON AND THE OPERATING CYLINDER	HYDRAULIC FLUID LEAK BETWEEN OPEN AND CLOSE FLUID PASSAGES AROUND PISTON	COULD RETARD, BUT NOT MAKE ENTIRELY INEFFECTIVE, THE CLOSING ACTION OR PISTONS. WELL PRESSURE EQUALIZED BETWEEN BORE AND BEHIND RAM WOULD NOT ASSIST, BUT NOT HINDER EITHER.	NOT CATASTROPHIC CAN CLOSE RAM WITH RAM LOCKING SCREW MANUALLY
	OPERATING CYLINDER 'O' RING	TO PROVIDE PRESSURE SEAL BETWEEN THE OPERATING CYLINDER AND THE BONNET AND INTERMEDIATE FLANGE	HYDRAULIC FLUID LEAK AT INTERFACE BETWEEN BONNET AND INTERMEDIATE FLANGE	SAME AS ABOVE	SAME AS ABOVE
	RAM CHANGING PISTON	TO PROVIDE PRESSURE SEAL BETWEEN THE RAM CHANGE PISTON AND THE RAM CHANGE CYLINDER	HYDRAULIC FLUID LEAK BETWEEN OPEN AND CLOSE FLUID PASSAGES AROUND PISTON	RETARD PROPER CLOSING AND OPENING OF RAMS HYDRAULICALLY	SAME AS ABOVE FOR CLOSING
	RAM CHANGING CYLINDER 'O' RINGS	TO PROVIDE PRESSURE SEALS BETWEEN THE RAM CHANGER CYLINDER AND THE BONNET AND THE INTERMEDIATE FLANGE	HYDRAULIC FLUID LEAK AT INTERFACE BETWEEN BONNET AND INTERMEDIATE FLANGE. LOSS OF FLUID TO ATMOSPHERE	SAME AS ABOVE	SAME AS ABOVE
BOP CONTROL SYSTEM	ACCUMULATOR	TO QUICKLY PROVIDE STORED FLUID ENERGY INDEPENDENT OF NORMAL RIG POWER, TO CLOSE ALL BOPS AND POWER–CONTROLLED VALVES	LOW PRESSURE DUE TO LEAK IN PRESSURE–LIMITING VALVE, BYPASS VALVE, RELIEF VALVE, CHECK VALVES	INABILITY TO OPERATE BOPS	COULD BE CATASTROPHIC
	ACCUMULATOR PUMP	TO CHARGE ACCUMULATOR WITH FLUID AND, IN EMERGENCIES, TO DIRECTLY CLOSE PREVENTERS	CLOGGED PUMP SUCTION STRAINER, WRONG PUMP ROTATION, SLIPPING BELT, DEFECTIVE SHAFT, DEFECTIVE COUPLING, STICKY RELIEF VALVE, POWER FAILURE	GRADUAL OR SUDDEN LOSS OF OUTPUT TO PREVENTERS	COULD BE CATASTROPHIC. CONDITIONAL THAT IT IS NECESSARY TO USE PUMP TO CLOSE PREVENTERS
BOP CONTROL SYSTEM	ANNULUS BOP REGULATOR	TO PROVIDE A CONSTANT REDUCED	DETAILED ANALYSIS WAS NOT	DETAILED ANALYSIS WAS NOT	[illegible]

Table F-2. Blowout Preventer and Associated Hydraulic Closing Equipment FMEA (Drilling and Completion Operations)

	HEAD GASKET	SEALS BETWEEN HEAD AND BODY TO PROVIDE PRESSURE SEAL FOR TOP CHAMBER	SAME AS ABOVE	SAME AS ABOVE	SAME AS ABOVE
	CONTRACTOR PISTON HEAD SEAL RING	PROVIDES PRESSURE SEAL BETWEEN TOP AND BOTTOM CHAMBERS	SAME AS ABOVE	RETARDS BOP CLOSURE AND POSSIBLY PREVENTS CLOSURE ALTOGETHER	COULD BE CATASTROPHIC
	LOWER CONTRACTOR PISTON SEAL RING	SEALS BETWEEN PISTON AND BODY TO PROVIDE PRESSURE SEAL FOR LOWER CHAMBER	SAME AS ABOVE	ALLOWS WELL PRESSURE TO ENTER INTO THE CONTROL SYSTEM	COULD BE CATASTROPHIC
PIPE AND BLIND RAM BOP	RAM PACKER	PROVIDES PRESSURE SEAL AROUND PIPE AND/OR ON MATING FACES OF RAMS	DAMAGED OR WORN	BOP COULD BE INEFFECTIVE IN SEALING ANNULUS DURING BLOWOUT	COULD BE CATASTROPHIC
	TOP RAM SEAL	PROVIDES PRESSURE SEAL BETWEEN BODY AND RAM	DAMAGED OR WORN	ALLOWS WELL PRESSURE USED TO ASSIST RAM CLOSING TO LEAK AND RESULTS IN LOSS SEAL	COULD BE CATASTROPHIC
	RAM TAIL ROD SEALS	TO PROVIDE A PRESSURE SEAL RAM TAIL ROD AND BONNET	HYDRAULIC FLUID LEAK BETWEEN CLOSING PASSAGE AND LOCKING SCREEN HOUSING	COULD RETARD, BUT NOT MAKE ENTIRELY INEFFECTIVE, THE CLOSING ACTION OF PISTONS. WELL PRESSURE EQUALIZED BETWEEN BORE AND BEHIND RAM WOULD NOT ASSIST, BUT NOT HINDER EITHER.	NOT CATASTROPHIC BOTH SEALS, THE WIPING "O" RING AND THE TAIL ROD SEAL RING, WOULD HAVE TO FAIL.
	BONNET OR DOOR SEALS	TO PROVIDE PRESSURE SEAL BETWEEN THE BONNET, OR DOOR, AND THE BODY AND PROVIDE SEAL BETWEEN BONNET BOLTS AND BONNET	WELL PRESSURE LEAK AT INTERFACE BETWEEN PREVENTER BODY AND INTERMEDIATE FLANGE	LOSS OF SEAL, FLOW, OR SAND CUTTING OUT DURING BLOWOUT	COULD BE CATASTROPHIC
	OPERATING PISTON 'O' RING	TO PROVIDE PRESSURE SEAL BETWEEN THE OPERATING PISTON AND THE OPERATING CYLINDER	HYDRAULIC FLUID LEAK BETWEEN OPEN AND CLOSE FLUID PASSAGES AROUND PISTON	COULD RETARD, BUT NOT MAKE ENTIRELY INEFFECTIVE, THE CLOSING ACTION OR PISTONS. WELL PRESSURE EQUALIZED BETWEEN BORE AND BEHIND RAM WOULD NOT ASSIST, BUT NOT HINDER EITHER.	NOT CATASTROPHIC CAN CLOSE RAM WITH RAM LOCKING SCREW MANUALLY
	OPERATING CYLINDER 'O' RING	TO PROVIDE PRESSURE SEAL BETWEEN THE OPERATING CYLINDER AND THE BONNET AND INTERMEDIATE FLANGE	HYDRAULIC FLUID LEAK AT INTERFACE BETWEEN BONNET AND INTERMEDIATE FLANGE	SAME AS ABOVE	SAME AS ABOVE
	RAM CHANGING PISTON	TO PROVIDE PRESSURE SEAL BETWEEN THE RAM CHANGE PISTON AND THE RAM CHANGE CYLINDER	HYDRAULIC FLUID LEAK BETWEEN OPEN AND CLOSE FLUID PASSAGES AROUND PISTON	RETARD PROPER CLOSING AND OPENING OF RAMS HYDRAULICALLY	SAME AS ABOVE FOR CLOSING
	RAM CHANGING CYLINDER 'O' RINGS	TO PROVIDE PRESSURE SEALS BETWEEN THE RAM CHANGER CYLINDER AND THE BONNET AND THE INTERMEDIATE FLANGE	HYDRAULIC FLUID LEAK AT INTERFACE BETWEEN BONNET AND INTERMEDIATE FLANGE. LOSS OF FLUID TO ATMOSPHERE	SAME AS ABOVE	SAME AS ABOVE
BOP CONTROL SYSTEM	ACCUMULATOR	TO QUICKLY PROVIDE STORED FLUID ENERGY INDEPENDENT OF NORMAL RIG POWER, TO CLOSE ALL BOPS AND POWER-CONTROLLED VALVES	LOW PRESSURE DUE TO LEAK IN PRESSURE-LIMITING VALVE, BYPASS VALVE, RELIEF VALVE, CHECK VALVES	INABILITY TO OPERATE BOPS	COULD BE CATASTROPHIC
	ACCUMULATOR PUMP	TO CHARGE ACCUMULATOR WITH FLUID AND, IN EMERGENCIES, TO DIRECTLY CLOSE PREVENTERS	CLOGGED PUMP SUCTION STRAINER, WRONG PUMP ROTATION, SLIPPING BELT, DEFECTIVE SHAFT, DEFECTIVE COUPLING, STICKY RELIEF VALVE, POWER FAILURE	GRADUAL OR SUDDEN LOSS OF OUTPUT TO PREVENTERS	COULD BE CATASTROPHIC. CONDITIONAL THAT IT IS NECESSARY TO USE PUMP TO CLOSE PREVENTERS
BOP CONTROL SYSTEM HYDRAULIC MANIFOLD	ANNULUS BOP REGULATOR	TO PROVIDE A CONSTANT REDUCED OUTPUT TO ANNULAR PREVENTER REGARDLESS OF THE HIGHER UPSTREAM PRESSURE AND TO ALLOW ADJUSTMENT TO ACCOMMODATE PIPE STRIPPING AND ROTATING	DETAILED ANALYSIS WAS NOT PERFORMED.	DETAILED ANALYSIS WAS NOT PERFORMED.	DETAILED ANALYSIS WAS NOT PERFORMED.
	4-WAY CONTROL VALVES	PROVIDES DIRECTIONAL CONTROL OF FLUID FROM MANIFOLD TO THE VARIOUS BOP, KILL VALVE, AND CHOKE OPEN AND CLOSE LINES	WORN OR LEAKS	GRADUAL OR SUDDEN LOSS OF HIGH PRESSURE TO PREVENTERS, CHOKE, OR KILL VALVE	COULD BE CATASTROPHIC
	PIPING, UNIONS, ETC.	PROVIDES DIRECTIONAL PRESSURE	BURSTS, PLUGGING, AND/OR LEAKS	GRADUAL OR SUDDEN LOSS OF HIGH PRESSURE TO PREVENTERS; CHOKE, AND KILL VALVE	COULD BE CATASTROPHIC
	STRAINERS	TO FILTER DIRT AND/OR FOREIGN MATERIALS FROM FLUIDS PRIOR TO CONTROL VALVES	CLOGGED	GRADUAL OR SUDDEN PLUGGING AND LOSS OF ABILITY TO OPERATE PREVENTERS, CHOKE, AND KILL VALVE	COULD BE CATASTROPHIC
HYDRAULIC FLUID	HYDRAULIC FLUID	TO PROVIDE A TRANSMISSION MEDIA FOR WORKING PRESSURE TO PREVENTERS AND OTHER POWER-CONTROLLED VALVES	DETERIORATION DUE TO TEMPERATURE, DIRT, FOREIGN MATTER, CAUSING MALFUNCTION OF VARIOUS CONTROL COMPONENTS; PLUGGING OF STRAINERS	GRADUAL OR SUDDEN LOSS OF HIGH PRESSURE TO PREVENTERS, KILL VALVE, OR CHOKE	COULD BE CATASTROPHIC
BOP STACK	FLANGES	TO PROVIDE PRESSURE SEAL BETWEEN PREVENTERS, DRILLING SPOOL, CASING HEAD, CHOKE MANIFOLD AND MANIFOLD COMPONENTS	RING GROVE OR GASKET DAMAGED OR WORN DESTROYING SEAL AND ALLOWING LEAK	CUT OUT DURING BLOWOUT ACTIVITY	COULD BE CATASTROPHIC

B

Table F-3. Activity Performed and Type of Flow Occurring During Blowouts

Location	Well Type	Type of Flow	Operation at Time of Incident
Maracaibo	Development	Gas/Saltwater	Coming out of Hole
Ventura County, California	Development	Gas/Oil	Displacing Mud with Oil
Kern County, California	Wildcat	Gas/Oil	Coming out of Hole
Kern County, California	Development	Gas	Coming out of Hole
Kern County, California	Development	Gas	Coming out of Hole
Kern County, California	Development	Gas	Coming out of Hole
Kern County, California	Wildcat	Gas	Circulating
Cook Inlet	Wildcat	Saltwater	Drilling
Cook Inlet	Wildcat	Gas	Circulating
Cook Inlet	Exploratory	Gas/Oil	Drilling
Off-shore Louisiana	Development	Gas	Drilling
Off-shore Louisiana	Development	Saltwater	Drilling
Off-shore Louisiana	Development	Gas	Drilling
Off-shore Louisiana	Development	Saltwater	Resumed Drilling after Freeing Pipe
Off-shore Louisiana	Wildcat	Gas	Drilling
Off-shore Louisiana	Extension	Gas/Saltwater	Drilling
Off-shore Louisiana	Development	Saltwater	Drilling
Off-shore Louisiana	Development	Saltwater	Drilling
Off-shore Louisiana	Wildcat	Saltwater	Shutdown
Off-shore Louisiana	Extension	Gas	Drilling
Off-shore Louisiana	Extension	Gas	Tripping
Texas	Wildcat	Gas	Coming out of Hole
Texas	Development	Gas	Coming out of Hole
Texas	Wildcat	Gas	Drilling
Texas	Development	Gas	Drilling
Ector County, Texas	-	Oil/Saltwater	Going into Hole
Andrews County, Texas	-	Oil/Gas	Freeing Tubing
Crockett County, Texas	-	Oil/Gas	Tripping
Mississippi	Wildcat	Oil	Drilling
Louisiana	Development	Gas	Coming out of Hole
Louisiana	Development	Gas	Coming out of Hole
Louisiana	Development	Gas	Circulating after Trip
Louisiana	Development	Gas	Coming out of Hole
West Coast	Development	Gas	Coming out of Hole, Circulating
West Coast	Development	Gas	Coming out of Hole after DST
Wyoming	Wildcat	Gas	Going into Hole
Duchesne County, Utah	-	Oil	Coming out of Hole
Duchesne County, Utah	-	Oil	Drilling
Alberta, Canada	-	-	DST
Alberta, Canada	-	-	Drilling Blind

Table F-4. Operational Function Performed at Time of Blowout on 40 Wells Versus Location

Activity Performed	Offshore La.	West Coast	Louisiana	Texas	Cook Inlet	Other	Total	% of Total
Drilling	9			2	2	3	16	40.0
Coming Out Of Hole		6	3	4		2	15	37.5
Going Into Hole				1		1	2	5.0
Circulating or Drilling After Freeing Pipe		1	1	1	1		4	10.0
Other	1	1				1	3	7.5
Total	10	8	4	8	3	7	40	100.0

Table F-5. Type of Flow During Blowouts on 38 Wells Versus Location

Type of Flow	Offshore La.	West Coast	Louisiana	Texas	Cook Inlet	Other	Total	% of Total
Oil						3	3	7.9
Gas	4	6	4	5	1	1	21	55.3
Saltwater	5				1		6	15.8
Combination	1	2		3	1	1	8	21.0
Total	10	8	4	8	3	5	38	100.0

Table F-6. Leaks Detected on Initial Working Pressure Tests of 1000 Ram-Type Blowout Preventer Stacks and Manifolding After Field Installation

Area of Leak	Number Of Leaks
BOP Ram Connector Rods Seal	36
BOP Ram Seal	14
BOP Bonnet Or Doors	40
Manifold Valves	42
BOP/Spool Flanges	62

severe environments during drilling operations and severe pressures during kick killing operations. This severity is substantiated by three occurrences of cutting out of equipment during the blowouts addressed in Table F-3.

Considering the potential seriousness of any blowout, each event and activity in the logic diagrams is assumed to be of substantial importance. Of most importance, however, are the events that allow early kick detection, since the earlier a kick is detected, the better the chance of preventing the potential blowout event.

The failure causes for blowout during drilling operations are present during completion operations. Therefore, to avoid duplication of effort, the completion operation has not been subjected to FMEA in this study. Figures F-2 through F-4 and Table F-2 are applicable for completion operations through exercise of judgment and elimination of causes clearly limited only to drilling operations.

F.6 PRODUCTION SYSTEM FTA

The Production System subsystem functions are configuration dependent; e.g., they are dependent upon the number and types of separators, and the manner in which they are piped into the system. It was determined through field survey trips and discussions with various people in the petroleum industry that typical production configurations are nonexistent. Therefore, the subsystem fault tree diagrams were derived by studying one type of equipment used in each subsystem, determining root causes for oil spillage from each equipment studied, and assigning the causes, with universal descriptors where possible, to any other applicable equipment used in the subsystem. In this manner, the diagram can be changed to describe the FTA of any equipment that may be used in a particular subsystem by using selective judgment.

The subsystems addressed were chosen after the data analysis indicated that they were the most frequent contributors to oil spillage. The well, wellhead, custody transfer, and water disposal subsystems were excluded from FTA because they did not appear to be principal sources of oil spillage. However, troublesome components in these subsystems, such as wellhead chokes and stuffing boxes, are addressed in Volume I . As a result of these considerations, the fault tree diagrams for the remaining subsystems are presented in Figures F-5 through F-9.

Considering that the major equipment in the local storage, treater, and separation subsystems are containment vessels with various associated equipments, the indication of oil spillage at these subsystems can be described as either overflow/overpressure or leak. The root causes of the subsystem level effects of overflow/overpressure and leak can be grouped into the general cause categories of either design-induced causes, equipment malfunction causes, operating/maintenance (O/M) causes, or outside party/event causes. Hereafter in this study, O/M causes are combined with outside party/event causes to group all human operating and third party causes, actions of livestock, and natural causes. Relative to the fault tree diagrams, overflow/overpressure is defined as spillage from the vessel through existing connections other than those intended for oil passage. Leak is defined as spillage through a breach of the vessel or associated equipment shell, fitting, gasket, or other unintended breaks. Design-induced causes are those that basically result from insufficient or inadequate considerations during planning and development of the production process for the oil field or oil wells involved. O/M or outside party/event causes result from O/M actions (or lack thereof), actions by third parties, or natural causes (such as high wind, hurricanes, or lightning).

The gathering subsystem (Figure F-5) addresses flowlines and manifolds with associated valving. Metering, chokes, pumps, and power are not included. Metering is generally associated with the custody transfer subsystem, chokes with the wellhead subsystem and pumps and power with the local storage subsystem.

The equipment used as the basis of the local storage subsystem (Figure F-6) was a heater treater; however, with selective consideration, most of the structure is applicable to chemical-electric and electric treaters, skimmers, and gun barrels, all of which are defined as treater subsystem equipment, with minimal change to the diagram.

The equipment used as the basis of the local storage subsystem (Figure F-7) are a welded tank with pump, swingline assembly, valving, fire arrester, automatic float gauge, and an equalization line to another tank. The same structure applies to a bolted tank with the same associated equipment, to tanks with less associated equipment (by selectively deleting various causes), or to sump tanks which are defined as local storage equipment.

The separation subsystem (Figure F-8) is based on a separator; however, the same diagram is applicable to scrubbers.

The safety shutdown subsystem (Figure F-9) addresses the potential causes of component malfunction of a gas pressure-operated safety shutdown system. The system consists of a surface-controlled subsurface safety valve, a surface safety valve actuator, a three-way pressure relay valve, and a monitoring pilot with sensor. Appendix J provides additional information on safety shutdown devices based on USGS inspection data of Gulf OCS facilities.

F.7 GATHERING/DISTRIBUTION SYSTEM FTA

The Gathering/Distribution System, consisting of pipeline, storage, gathering, pumping, and emergency safety subsystems, was not addressed by a separate FTA. This decision was made because data analysis showed that 73 percent of the Gathering/Distribution System spills were attributed to pipe in the pipeline subsystem and 20 percent were attributable to the gathering subsystem (see Table E-35, Appendix E). Consequently, the FTA on the gathering subsystem in the Production System, Figure F-5, is translatable to address these major spill areas in the Gathering/Distribution System; the local storage subsystem in the Production System, Figure F-7, is translatable to the storage subsystem in the Gathering/Distribution System. As a result, duplicate effort and fault tree diagrams have been avoided.

F.8 REFERENCES

1. W.C. Goins, "Blowout Prevention, Practical Drilling Technology, Volume 1," 1969, Gulf Publishing Company.

2. Bill Rehm, "Pressure Control in Drilling," 1969, 1970, The Oil and Gas Journal, The Petroleum Publishing Company.

3. "Lessons in Rotary Drilling, September 1971, Unit III - Lesson 3, Blowout Prevention (Revised)," Petroleum Extension Service, The University of Texas in cooperation with American Association of Oilwell Drilling Contractors.

4. John L. Kennedy, "Losing Control While Drilling: a 32-Well Look at Causes and Results," pp 121-126, September 20, 1971, The Oil and Gas Journal.

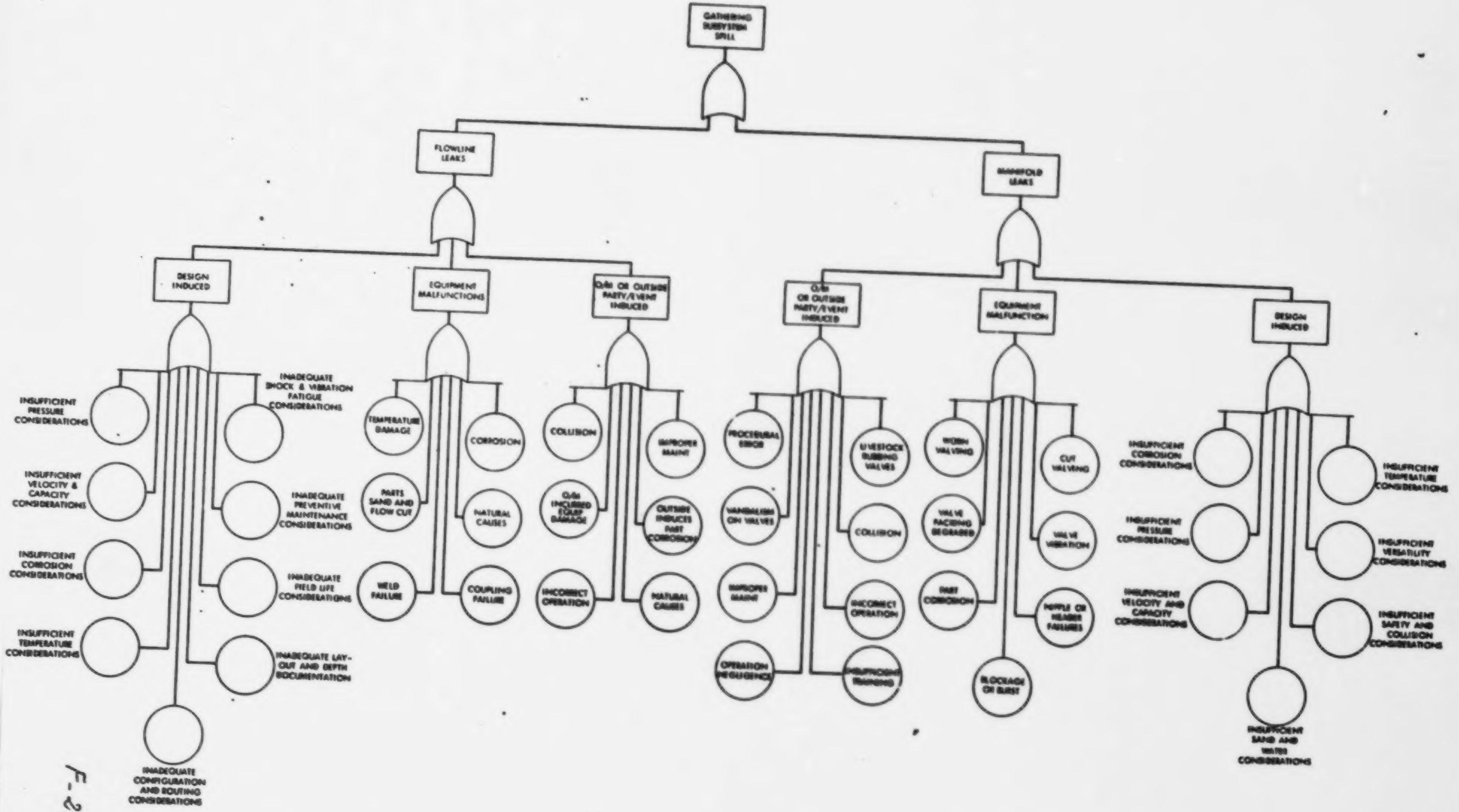

GATHERING SUBSYSTEM SPILL
FLOWLINE LEAKS
MANIFOLD LEAKS
DESIGN INDUCED
EQUIPMENT MALFUNCTIONS
O&M OR OUTSIDE PARTY/EVENT INDUCED
O&M OR OUTSIDE PARTY/EVENT INDUCED
EQUIPMENT MALFUNCTION
DESIGN INDUCED
INSUFFICIENT PRESSURE CONSIDERATIONS
INSUFFICIENT VELOCITY & CAPACITY CONSIDERATIONS
INSUFFICIENT CORROSION CONSIDERATIONS
INSUFFICIENT TEMPERATURE CONSIDERATIONS
INADEQUATE CONFIGURATION AND ROUTING CONSIDERATIONS
INADEQUATE SHOCK & VIBRATION FATIGUE CONSIDERATIONS
INADEQUATE PREVENTIVE MAINTENANCE CONSIDERATIONS
INADEQUATE FIELD LIFE CONSIDERATIONS
INADEQUATE LAY-OUT AND DEPTH DOCUMENTATION
TEMPERATURE DAMAGE
PARTS SAND AND FLOW CUT
WELD FAILURE
CORROSION
NATURAL CAUSES
COUPLING FAILURE
COLLISION
O&M INCURRED EQUIP DAMAGE
INCORRECT OPERATION
IMPROPER MAINT
OUTSIDE INDUCES PART CORROSION
NATURAL CAUSES
PROCEDURAL ERROR
VANDALISM ON VALVES
IMPROPER MAINT
OPERATION NEGLIGENCE
LIVESTOCK RUBBING VALVES
COLLISION
INCORRECT OPERATION
INSUFFICIENT TRAINING
WORN VALVING
VALVE PACKING DEGRADED
PART CORROSION
BLOCKAGE OR BURST
CUT VALVING
VALVE VIBRATION
NIPPLE OR HEADER FAILURES
INSUFFICIENT CORROSION CONSIDERATIONS
INSUFFICIENT PRESSURE CONSIDERATIONS
INSUFFICIENT VELOCITY AND CAPACITY CONSIDERATIONS
INSUFFICIENT SAND AND WATER CONSIDERATIONS
INSUFFICIENT TEMPERATURE CONSIDERATIONS
INSUFFICIENT VERSATILITY CONSIDERATIONS
INSUFFICIENT SAFETY AND COLLISION CONSIDERATIONS

Figure F-5. Fault Tree Diagram
for the Gathering Subsystem
(Production and Gathering/Distributio

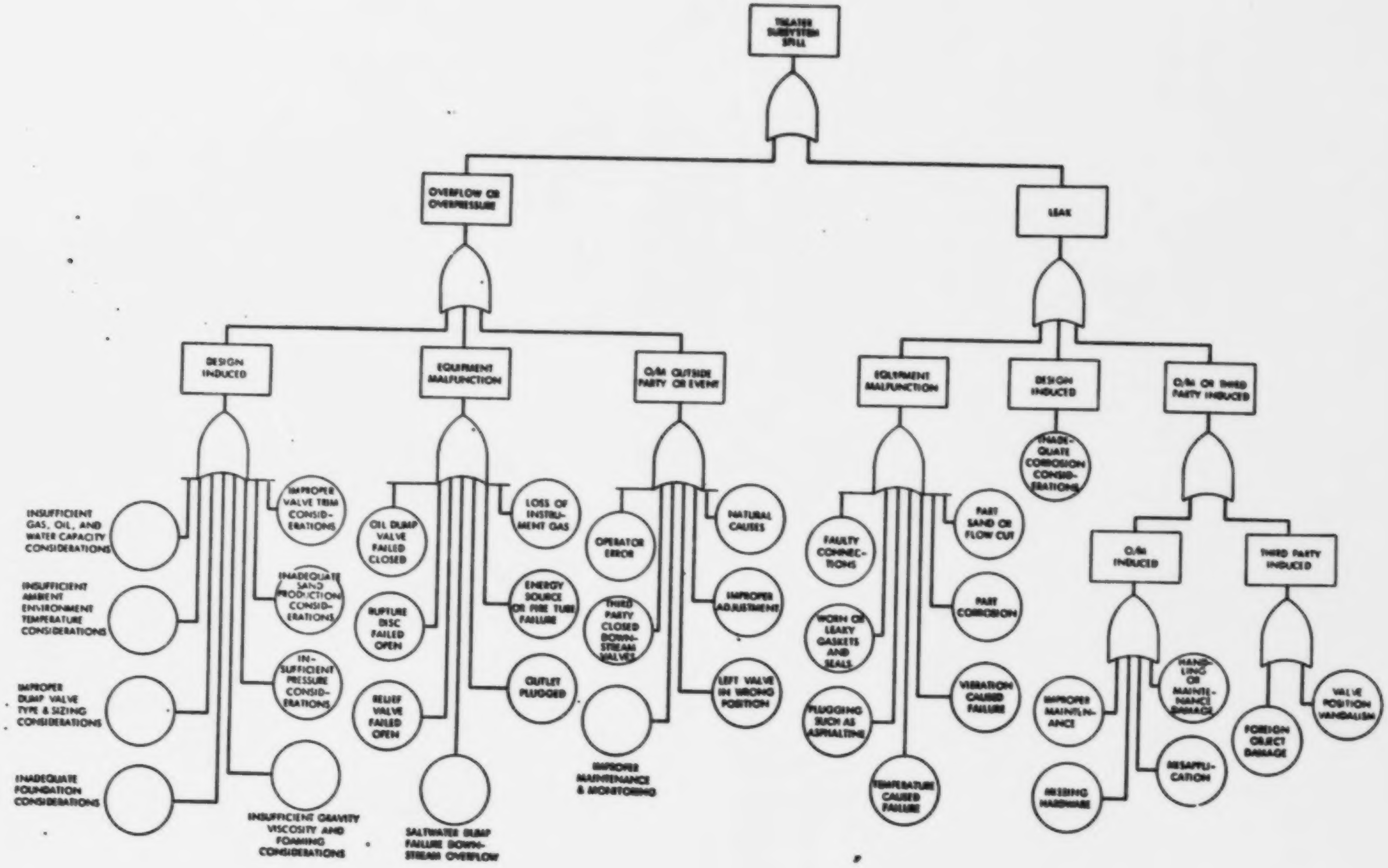

TREATER SUBSYSTEM SPILL
OVERFLOW OR OVERPRESSURE
LEAK
DESIGN INDUCED
EQUIPMENT MALFUNCTION
O/M OUTSIDE PARTY OR EVENT
EQUIPMENT MALFUNCTION
DESIGN INDUCED
O/M OR THIRD PARTY INDUCED
INSUFFICIENT GAS, OIL, AND WATER CAPACITY CONSIDERATIONS
INSUFFICIENT AMBIENT ENVIRONMENT TEMPERATURE CONSIDERATIONS
IMPROPER DUMP VALVE TYPE & SIZING CONSIDERATIONS
INADEQUATE FOUNDATION CONSIDERATIONS
IMPROPER VALVE TRIM CONSIDERATIONS
INADEQUATE SAND PRODUCTION CONSIDERATIONS
INSUFFICIENT PRESSURE CONSIDERATIONS
INSUFFICIENT GRAVITY VISCOSITY AND FOAMING CONSIDERATIONS
OIL DUMP VALVE FAILED CLOSED
RUPTURE DISC FAILED OPEN
RELIEF VALVE FAILED OPEN
SALTWATER DUMP FAILURE DOWNSTREAM OVERFLOW
LOSS OF INSTRUMENT GAS
ENERGY SOURCE OR FIRE TUBE FAILURE
OUTLET PLUGGED
OPERATOR ERROR
THIRD PARTY CLOSED DOWNSTREAM VALVES
IMPROPER MAINTENANCE & MONITORING
NATURAL CAUSES
IMPROPER ADJUSTMENT
LEFT VALVE IN WRONG POSITION
FAULTY CONNECTIONS
WORN OR LEAKY GASKETS AND SEALS
PLUGGING SUCH AS ASPHALTING
TEMPERATURE CAUSED FAILURE
PART SAND OR FLOW CUT
PART CORROSION
VIBRATION CAUSED FAILURE
INADEQUATE CORROSION CONSIDERATIONS
O/M INDUCED
THIRD PARTY INDUCED
IMPROPER MAINTENANCE
MISSING HARDWARE
HANDLING OR MAINTENANCE DAMAGE
MISAPPLICATION
FOREIGN OBJECT DAMAGE
VALVE POSITION VANDALISM

Figure F-6. Fault Tree Diagram for the Treater Subsystem

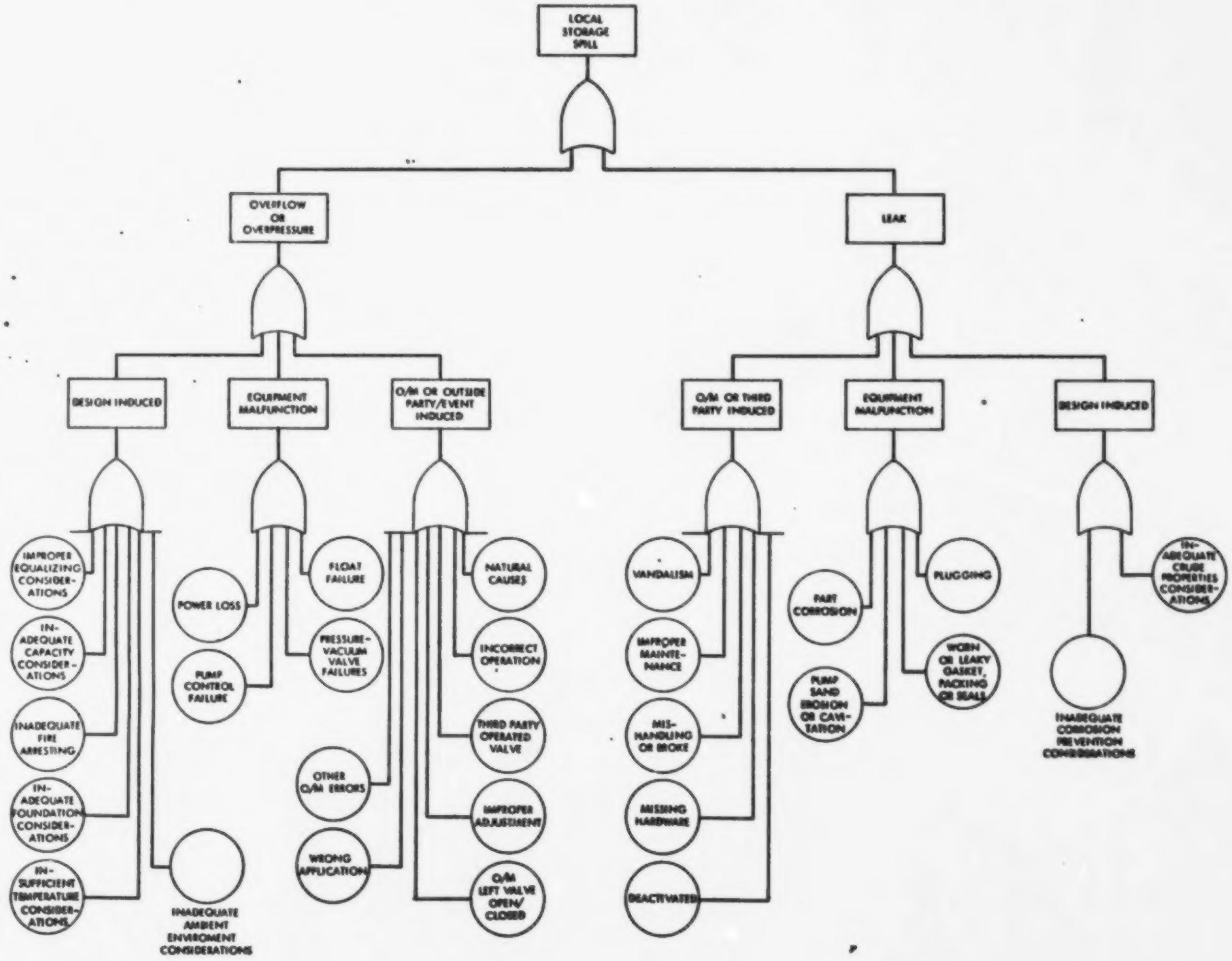

LOCAL STORAGE SPILL
OVERFLOW OR OVERPRESSURE
LEAK
DESIGN INDUCED
EQUIPMENT MALFUNCTION
O/M OR OUTSIDE PARTY/EVENT INDUCED
O/M OR THIRD PARTY INDUCED
EQUIPMENT MALFUNCTION
DESIGN INDUCED
IMPROPER EQUALIZING CONSIDER-ATIONS
IN-ADEQUATE CAPACITY CONSIDER-ATIONS
INADEQUATE FIRE ARRESTING
IN-ADEQUATE FOUNDATION CONSIDER-ATIONS
IN-SUFFICIENT TEMPERATURE CONSIDER-ATIONS
INADEQUATE AMBIENT ENVIROMENT CONSIDERATIONS
POWER LOSS
PUMP CONTROL FAILURE
FLOAT FAILURE
PRESSURE-VACUUM VALVE FAILURES
OTHER O/M ERRORS
WRONG APPLICATION
NATURAL CAUSES
INCORRECT OPERATION
THIRD PARTY OPERATED VALVE
IMPROPER ADJUSTMENT
O/M LEFT VALVE OPEN/CLOSED
VANDALISM
IMPROPER MAINTE-NANCE
MIS-HANDLING OR BROKE
MISSING HARDWARE
DEACTIVATED
PART CORROSION
PUMP SAND EROSION OR CAVI-TATION
PLUGGING
WORN OR LEAKY GASKET, PACKING OR SEALS
IN-ADEQUATE CRUDE PROPERTIES CONSIDER-ATIONS
INADEQUATE CORROSION PREVENTION CONSIDERATIONS

Figure F-7. Fault Tree Diagram
for the Local Storage Subsystem
(Production and Gathering/Distribution)

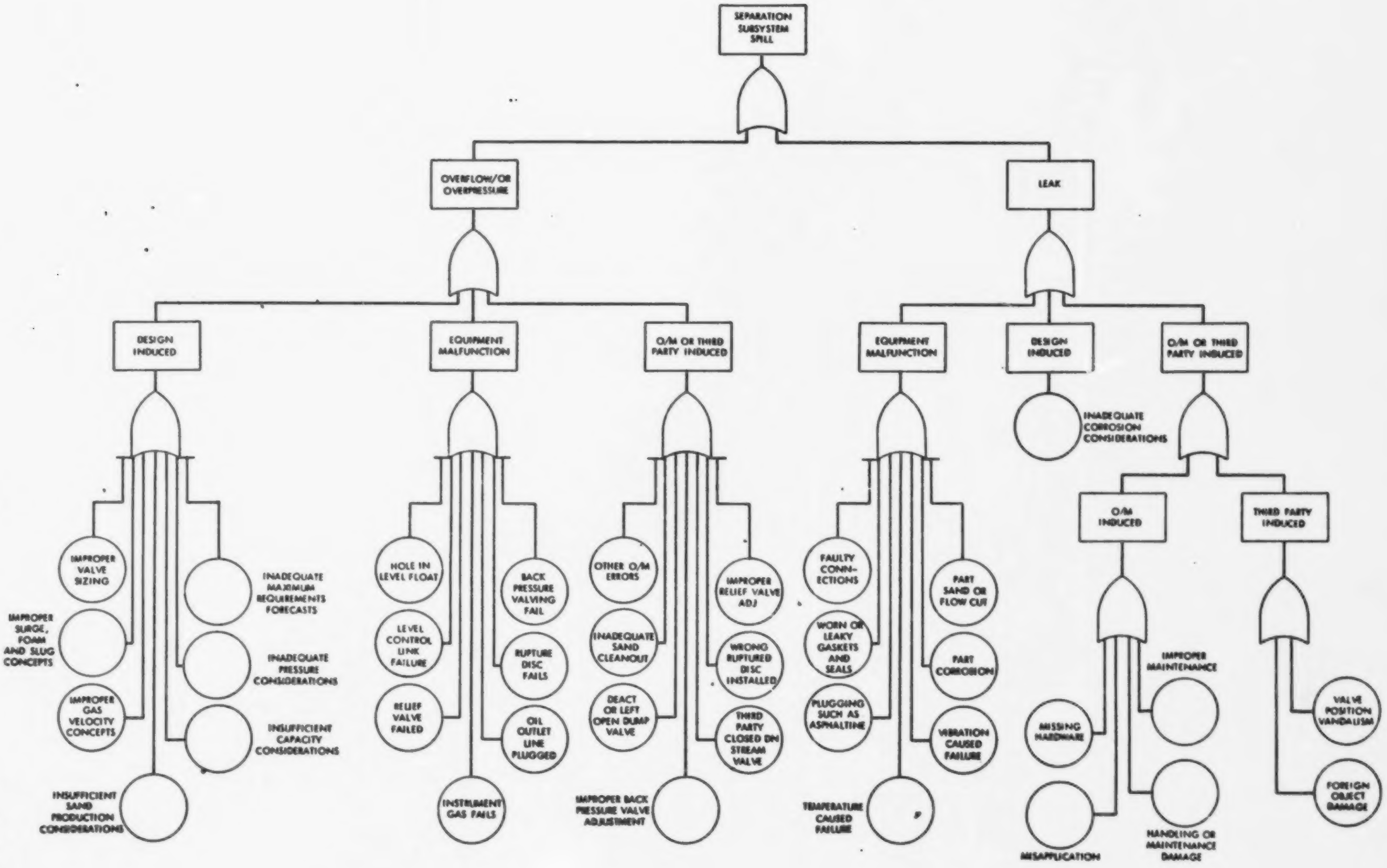
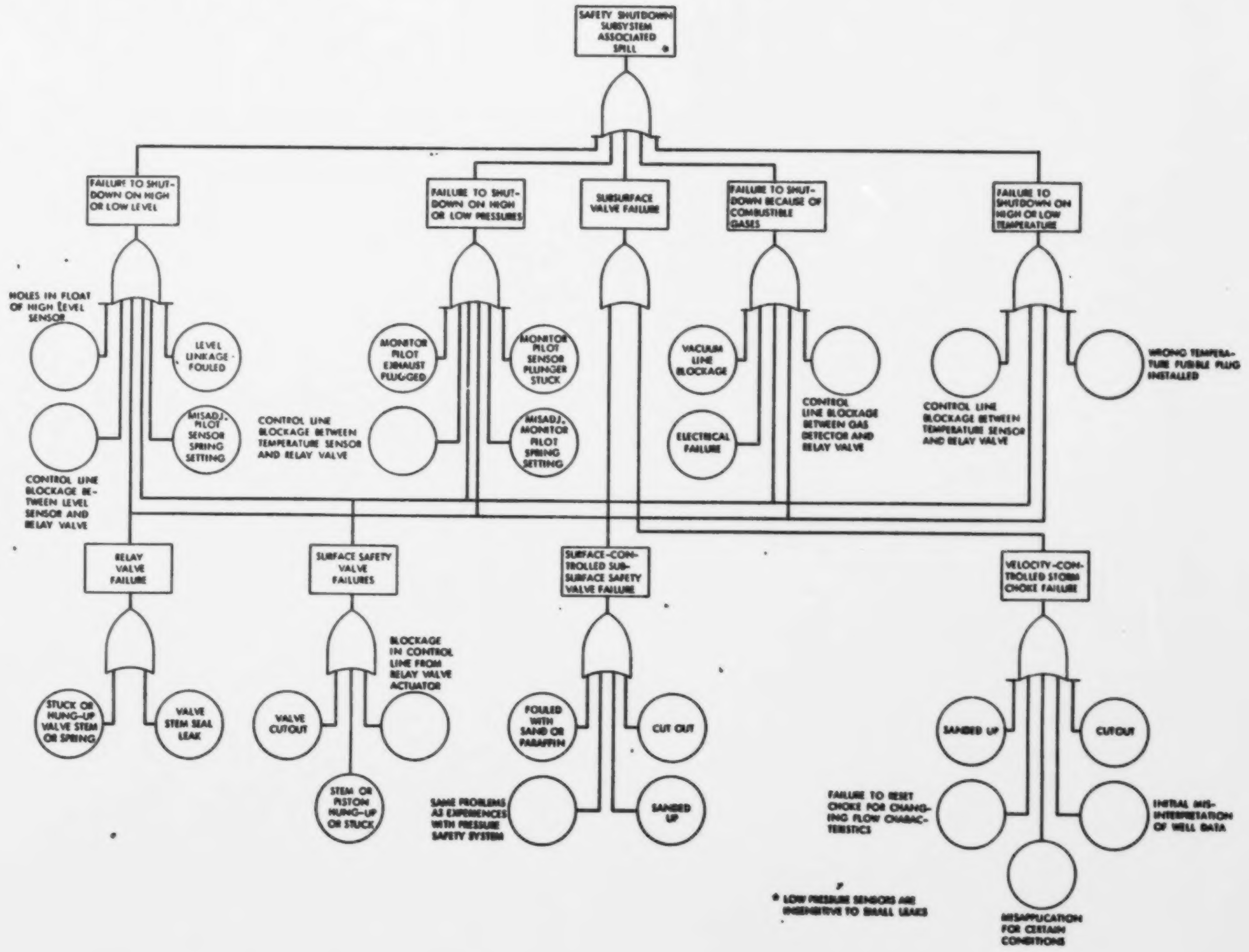

SEPARATION SUBSYSTEM SPILL
OVERFLOW/OR OVERPRESSURE
LEAK
DESIGN INDUCED
EQUIPMENT MALFUNCTION
O/M OR THIRD PARTY INDUCED
EQUIPMENT MALFUNCTION
DESIGN INDUCED
O/M OR THIRD PARTY INDUCED
INADEQUATE CORROSION CONSIDERATIONS
O/M INDUCED
THIRD PARTY INDUCED
IMPROPER VALVE SIZING
IMPROPER SURGE, FOAM AND SLUG CONCEPTS
IMPROPER GAS VELOCITY CONCEPTS
INSUFFICIENT SAND PRODUCTION CONSIDERATIONS
INADEQUATE MAXIMUM REQUIREMENTS FORECASTS
INADEQUATE PRESSURE CONSIDERATIONS
INSUFFICIENT CAPACITY CONSIDERATIONS
HOLE IN LEVEL FLOAT
LEVEL CONTROL LINK FAILURE
RELIEF VALVE FAILED
INSTRUMENT GAS FAILS
BACK PRESSURE VALVING FAIL
RUPTURE DISC FAILS
OIL OUTLET LINE PLUGGED
OTHER O/M ERRORS
INADEQUATE SAND CLEANOUT
DEACT OR LEFT OPEN DUMP VALVE
IMPROPER BACK PRESSURE VALVE ADJUSTMENT
IMPROPER RELIEF VALVE ADJ
WRONG RUPTURED DISC INSTALLED
THIRD PARTY CLOSED DN STREAM VALVE
FAULTY CONN-ECTIONS
WORN OR LEAKY GASKETS AND SEALS
PLUGGING SUCH AS ASPHALTINE
TEMPERATURE CAUSED FAILURE
PART SAND OR FLOW CUT
PART CORROSION
VIBRATION CAUSED FAILURE
MISSING HARDWARE
MISAPPLICATION
IMPROPER MAINTENANCE
HANDLING OR MAINTENANCE DAMAGE
VALVE POSITION VANDALISM
FOREIGN OBJECT DAMAGE

Figure F-8. Fault Tree Diagram for the Separation Subsystem


SAFETY SHUTDOWN SUBSYSTEM ASSOCIATED SPILL *
FAILURE TO SHUT-DOWN ON HIGH OR LOW LEVEL
FAILURE TO SHUT-DOWN ON HIGH OR LOW PRESSURES
SUBSURFACE VALVE FAILURE
FAILURE TO SHUT-DOWN BECAUSE OF COMBUSTIBLE GASES
FAILURE TO SHUTDOWN ON HIGH OR LOW TEMPERATURE
HOLES IN FLOAT OF HIGH LEVEL SENSOR
LEVEL LINKAGE FOULED
MISADJ. PILOT SENSOR SPRING SETTING
CONTROL LINE BLOCKAGE BE-TWEEN LEVEL SENSOR AND RELAY VALVE
MONITOR PILOT EXHAUST PLUGGED
MONITOR PILOT SENSOR PLUNGER STUCK
CONTROL LINE BLOCKAGE BETWEEN TEMPERATURE SENSOR AND RELAY VALVE
MISADJ. MONITOR PILOT SPRING SETTING
VACUUM LINE BLOCKAGE
ELECTRICAL FAILURE
CONTROL LINE BLOCKAGE BETWEEN GAS DETECTOR AND RELAY VALVE
CONTROL LINE BLOCKAGE BETWEEN TEMPERATURE SENSOR AND RELAY VALVE
WRONG TEMPERA-TURE FUSIBLE PLUG INSTALLED
RELAY VALVE FAILURE
SURFACE SAFETY VALVE FAILURES
SURFACE-CON-TROLLED SUB-SURFACE SAFETY VALVE FAILURE
VELOCITY-CON-TROLLED STORM CHOKE FAILURE
STUCK OR HUNG-UP VALVE STEM OR SPRING
VALVE STEM SEAL LEAK
VALVE CUTOUT
BLOCKAGE IN CONTROL LINE FROM RELAY VALVE ACTUATOR
STEM OR PISTON HUNG-UP OR STUCK
FOULED WITH SAND OR PARAFFIN
CUT OUT
SAME PROBLEMS AS EXPERIENCES WITH PRESSURE SAFETY SYSTEM
SANDED UP
SANDED UP
CUTOUT
FAILURE TO RESET CHOKE FOR CHANG-ING FLOW CHARAC-TERISTICS
INITIAL MIS-INTERPRETATION OF WELL DATA
MISAPPLICATION FOR CERTAIN CONDITIONS

* LOW PRESSURE SENSORS ARE INSENSITIVE TO SMALL LEAKS

Figure F-9. Fault Tree Diagram for the Safety Subsystem

APPENDIX G

CONSIDERATIONS OF HAZARDOUS ENVIRONMENT ON PETROLEUM SYSTEMS

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APPENDIX G

CONSIDERATIONS OF HAZARDOUS NATURAL ENVIRONMENT ON PETROLEUM SYSTEMS

G.1 INTRODUCTORY SUMMARY

The spill prevention program described in this report must consider the catastrophic results of natural environmental hazards. Oil spillage may occur from several different sources. In the United States, 200,000 miles of pipeline carry more than a billion tons of oil and gas annually. The pipelines cross waterways and reservoirs and are subject to cracks, punctures, corrosion, and other causes of leakage. Offshore oil and gas exploration and production, blowout of wells, and dumping of drilling muds and oil-soaked wastes are significant potential oil spill sources. Other sources include unavoidable accidents and actions of the hazardous natural environment, such as storms, ice, tsunamis, and earthquakes. This appendix provides a guideline and basic information about environmental hazards and their effect on petroleum systems.

Petroleum industry systems are exposed to many natural hazards (see Figure G-1). The industry is especially affected by hurricanes, earthquakes, and tsunamis because much of its operations and systems are located along the Gulf and Pacific Coasts and in southern Alaska. Because of the catastrophic nature of most natural hazards and the limited time for which petroleum spill records have been kept, an accurate record of past oil spill incidents caused by natural hazards is not available. Table G-1 lists the spill record obtained in this survey. Although this information is incomplete, the objective is to describe the characteristics of various natural hazards and, based on available published data, augment the spill record to the maximum extent possible. Each natural hazard will be treated individually, and its emphasis will vary according to its state-of-knowledge.

G.2 DISCUSSION OF INDIVIDUAL NATURAL HAZARDS

The following paragraphs describe the characteristics of individual natural hazards and the documented (and inferred) effects on petroleum systems.

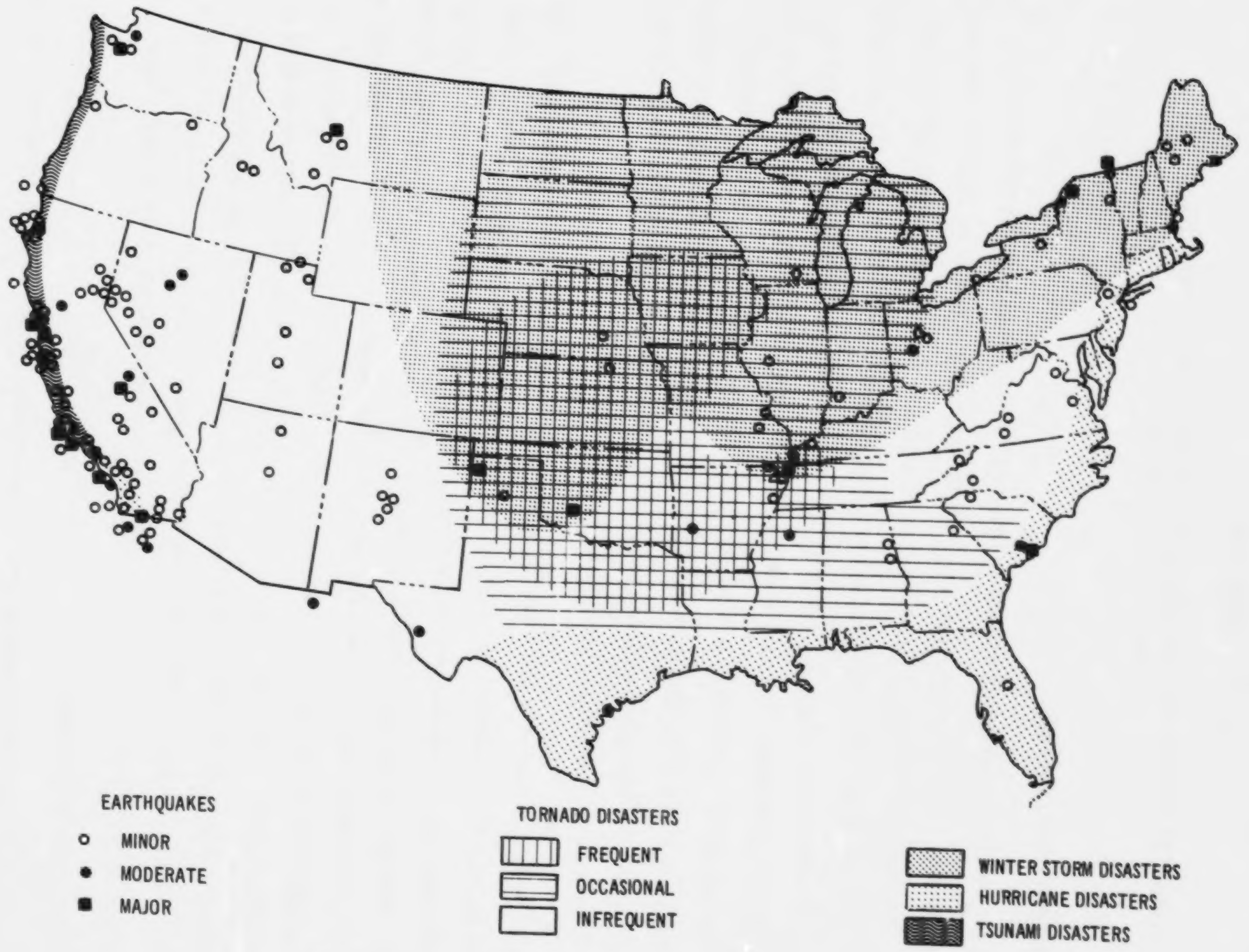

EARTHQUAKES
○ MINOR
● MODERATE
■ MAJOR
TORNADO DISASTERS
FREQUENT
OCCASIONAL
INFREQUENT
WINTER STORM DISASTERS
HURRICANE DISASTERS
TSUNAMI DISASTERS

Figure G-1. Geographic Distribution of Natural Hazards

Table G-1. Reported Oil Spills Caused by Recent Hurricanes

Storm	Date	Location of Spill	Losses
Camille	August, 1969	Plaquemines Par., La.	(Undetermined)
Camille	August, 1969	Plaquemines Par., La.	1000-5000 bbls.
Camille	August, 1969	Plaquemines Par., La.	10,000 bbls.
Camille	August, 1969	Plaquemines Par., La.	1000-5000 bbls.
Camille	August, 1969	Plaquemines Par., La.	5000-10,000 bbls.
Camille	August, 1969	Plaquemines Par., La.	10,000 bbls.
Celia	August, 1970	San Patricio Co., Texas	223,183 bbls.*
Celia	August, 1970	San Patricio Co., Texas	$47,000**
Fern	September, 1971	Refugio Co., Texas	100-240 bbls.
Fern	September, 1971	Plaquemines Par., La.	2.6-10 bbls.
Edith	September, 1971	San Patricio Co., Texas	240-500 bbls.
Edith	September, 1971	San Patricio Co., Texas	240-500 bbls.
Edith	September, 1971	St. Mary Par., La.	2.6-10 bbls.
Edith	September, 1971	St. Mary Par., La.	500-1000 bbls.

*Company reported crude oil burned in a fire caused by Hurricane Celia.

**Company reported that Hurricane Celia blew top off of tank, causing fire.

G.2.1 Hurricanes

Each year hurricanes threaten petroleum systems on the Gulf and Atlantic coasts. In the Louisiana Gulf Coast area alone, approximately 1120 platforms and other structures, 3942 holes with 6415 oil and gas completions, and approximately 2700 miles of pipeline serving 29 receiving onshore stations are exposed and vulnerable to the environmental extremes generated by a hurricane (see Figure G-2). Although the petroleum industry has recognized this problem and spent millions of dollars to attenuate the impact, potential oil spill problems continue to exist.

A typical design storm is one that is expected to occur about once every hundred years. About 95 percent of the time the sea conditions are expected to be incapable of producing a wave causing more than one fourth the design load. In the 1960s, four 100-year frequency storms hit the Gulf Coast area causing widespread damage estimated at $500 million (World Oil, October 1969). Hurricanes Carla (1961), Hilda (1964), Betsy (1965), and Camille (1969), and others (Figure G-3) will long be remembered. Hurricanes Hilda and Betsy destroyed 22 offshore structures and severely damaged 10 others (Blumberg and Strader, 1969). Hurricane Camille, called by the United States Weather Bureau the most powerful storm to strike the United States since 1890, battered the Mississippi Gulf coast, but its damage was only about half as severe as that of Betsy. In every case, the petroleum systems hit hardest were offshore platforms, barges, rigs, storage tanks, and transmission facilities. However, through careful planning, every evacuation, and shut-in of offshore facilities due to early warning systems, oil spills have been kept to a minimum. Recent storms (e.g., Edith and Fern, 1971), have caused relatively little oil industry damage and few spills. Celia, in 1970, was responsible for several oil storage tank fires. The implementation of early warning systems, the development of storm safety chokes, and the application of design knowledge gained from instrument data on wind and wave forces have contributed to a reduced number of spills and less damage from recent storms.

G.2.2 Earthquakes

An earthquake can alter the environment in a catastrophic manner. Every State is vulnerable to and has felt the effects of earthquakes (see Figure G-4). Most of the nation's seismic activity is centered along the Pacific Coast and in Nevada. The East Coast, by contrast, is relatively inactive seismicly but has nevertheless experienced noteworthy earthquake damage.

The San Francisco earthquake of April 18, 1906, which touched off fires that nearly razed the city and took an estimated 700 lives, was the most catastrophic earthquake

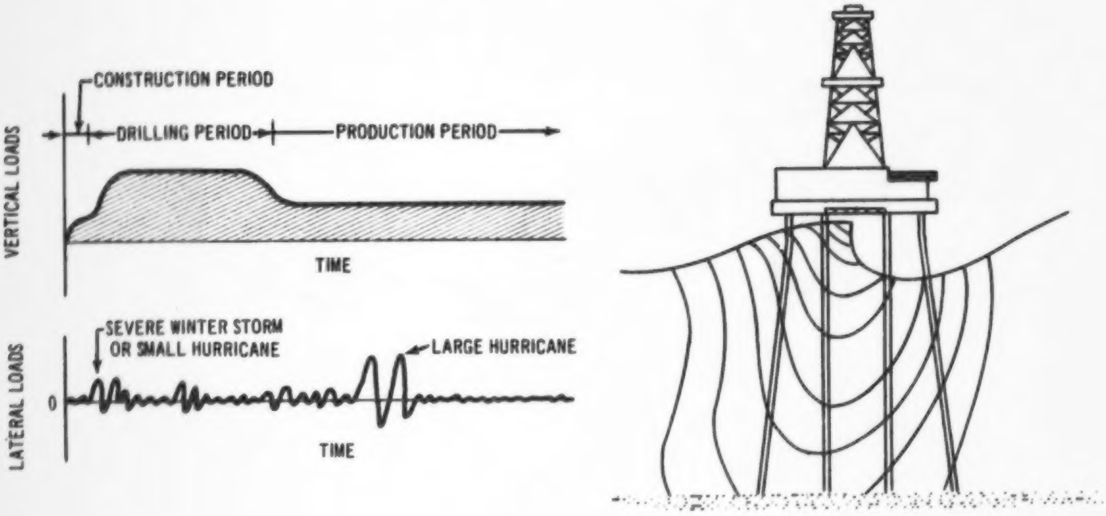

CONSTRUCTION PERIOD
DRILLING PERIOD
PRODUCTION PERIOD
VERTICAL LOADS
TIME
SEVERE WINTER STORM OR SMALL HURRICANE
LARGE HURRICANE
LATERAL LOADS
0
TIME

Figure G-2. Illustrations of Wave Forces Acting on Petroleum Systems

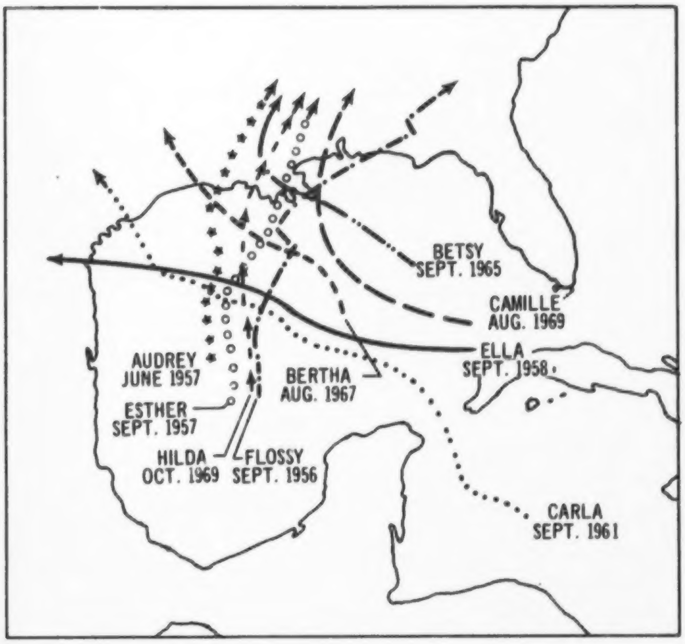
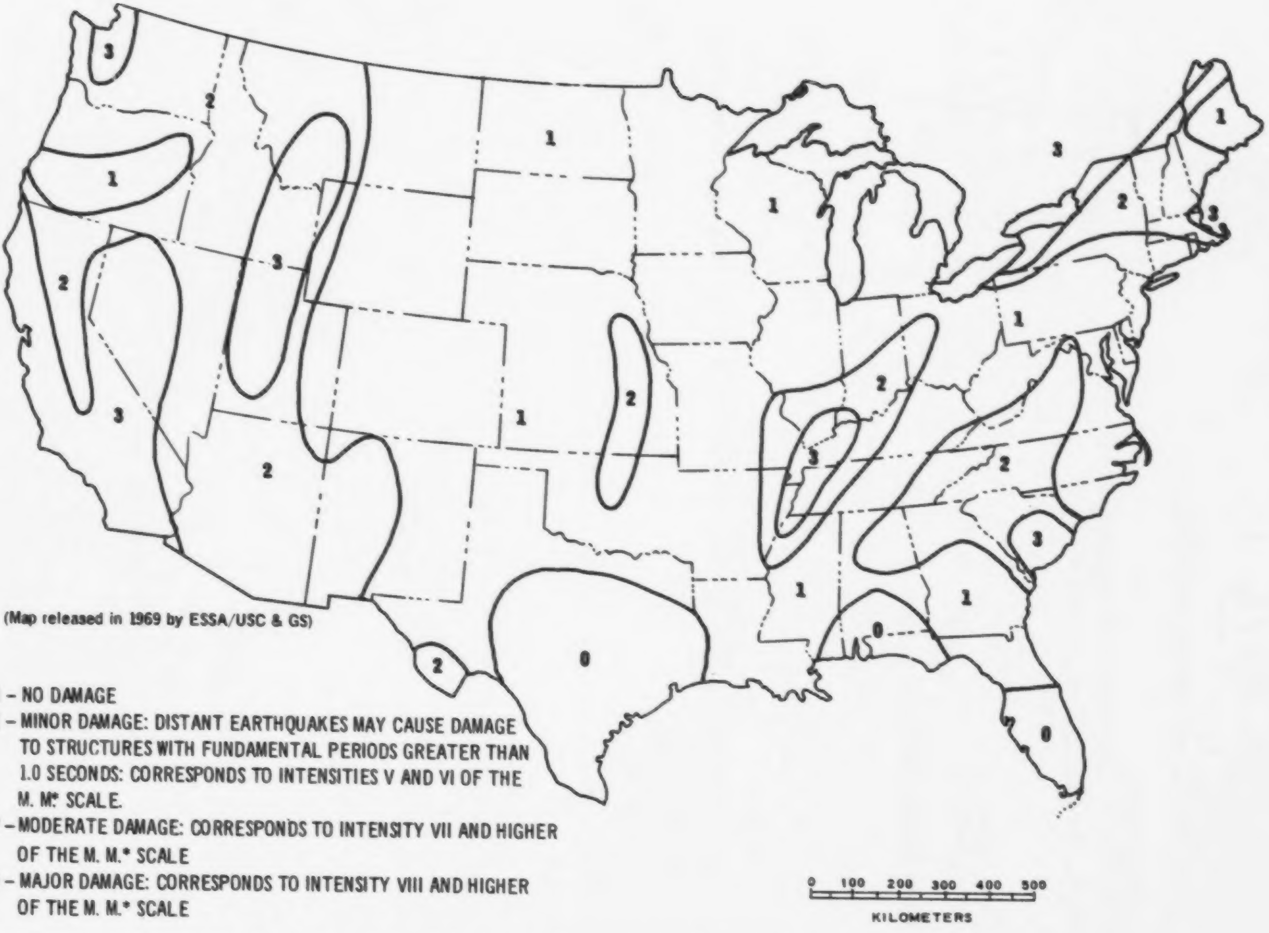

BETSY SEPT. 1965
CAMILLE AUG. 1969
ELLA SEPT. 1958
AUDREY JUNE 1957
BERTHA AUG. 1967
ESTHER SEPT. 1957
HILDA OCT. 1969
FLOSSY SEPT. 1956
CARLA SEPT. 1961

Figure G-3. Primary Path of Major Hurricanes



(Map released in 1969 by ESSA/USC & GS)

ZONE 0 – NO DAMAGE
ZONE 1 – MINOR DAMAGE: DISTANT EARTHQUAKES MAY CAUSE DAMAGE TO STRUCTURES WITH FUNDAMENTAL PERIODS GREATER THAN 1.0 SECONDS: CORRESPONDS TO INTENSITIES V AND VI OF THE M. M.* SCALE.
ZONE 2 – MODERATE DAMAGE: CORRESPONDS TO INTENSITY VII AND HIGHER OF THE M. M.* SCALE
ZONE 3 – MAJOR DAMAGE: CORRESPONDS TO INTENSITY VIII AND HIGHER OF THE M. M.* SCALE

*MODIFIED MERCALLI INTENSITY SCALE OF 1931 – A QUALITATIVE SCALE OF DAMAGE INTENSITY AT THE EARTH'S SURFACE FOR EVALUATING REPORTED HUMAN OBSERVATIONS

Figure G-4. Seismic Zones of the United States yet recorded in the United States. In the east, the greatest shock was experienced in Charleston, South Carolina, on August 31, 1886, resulting in 60 deaths and $23 million in property damage. The San Fernando Valley, California, earthquake of February 9, 1971, killed 65 persons and caused property damage estimated at $500 million. Table G-2 lists earthquakes which have caused $1 million or more damage in the United States.

The earthquake disaster potential in California is now at least 10 times greater than it was at the time of the 1906 San Francisco earthquake (see Earthquake Engineering Research, 1969). Table G-3 lists the expectation of earthquakes in California. It shows that some 40 earthquakes having magnitudes between 6.25 and 6.75 on the Richter Scale (including the magnitude of 6.4 assigned for the San Fernando 1971 earthquake) can be expected to occur in any given 100-year period in California. The percent probability of ground acceleration (a damage diagnostic) at a given location in California is given in Table G-4.

From 1865, to 1965, 77 earthquakes occurred in or near California and caused damage to California hydraulic systems. Forty cases of damage to petroleum structures were also reported (see Department of Water Resources, State of California). Figure G-5, which is keyed to Attachment 1 to this appendix, shows damage locations. Highlights of three specific damage cases will be described below for emphasis.

The San Andreas fault zone ruptured over an observed distance of about 180 miles during the great San Francisco quake (magnitude 8.3) of April 18, 1906. Gas pipe as far as 150 miles from the epicenter were ruptured. The roofs of six large oil tanks at a pumping station located 156 miles from the epicenter collapsed, resulting in considerable oil spillage. An oil pipeline located some 120 miles from the epicenter was twisted, broken, and pulled apart in more than 20 places (Lawson, 1908).

In July, 1952, the Kern County earthquake occurred in the southern San Joaquin Valley with a magnitude of 7.7. Effects of this large shock included open fractures in the valley floor, broken pipelines, oil spills caused by surface waves splashing oil from numerous sumps throughout the area, collapse of oil and butane storage tanks, kinked tubing, and collapsed casing. Extensive damage to the Paloma Cycling Plant, southwest of Bakersfield, resulted from a combination of the earthquake, fire, and an explosion, and amounted to an estimated $1.8 million.

Table G-2. Earthquakes Which Have Caused $1 Million or More Damage in the United States. (Source: National Earthquake Information Center.)

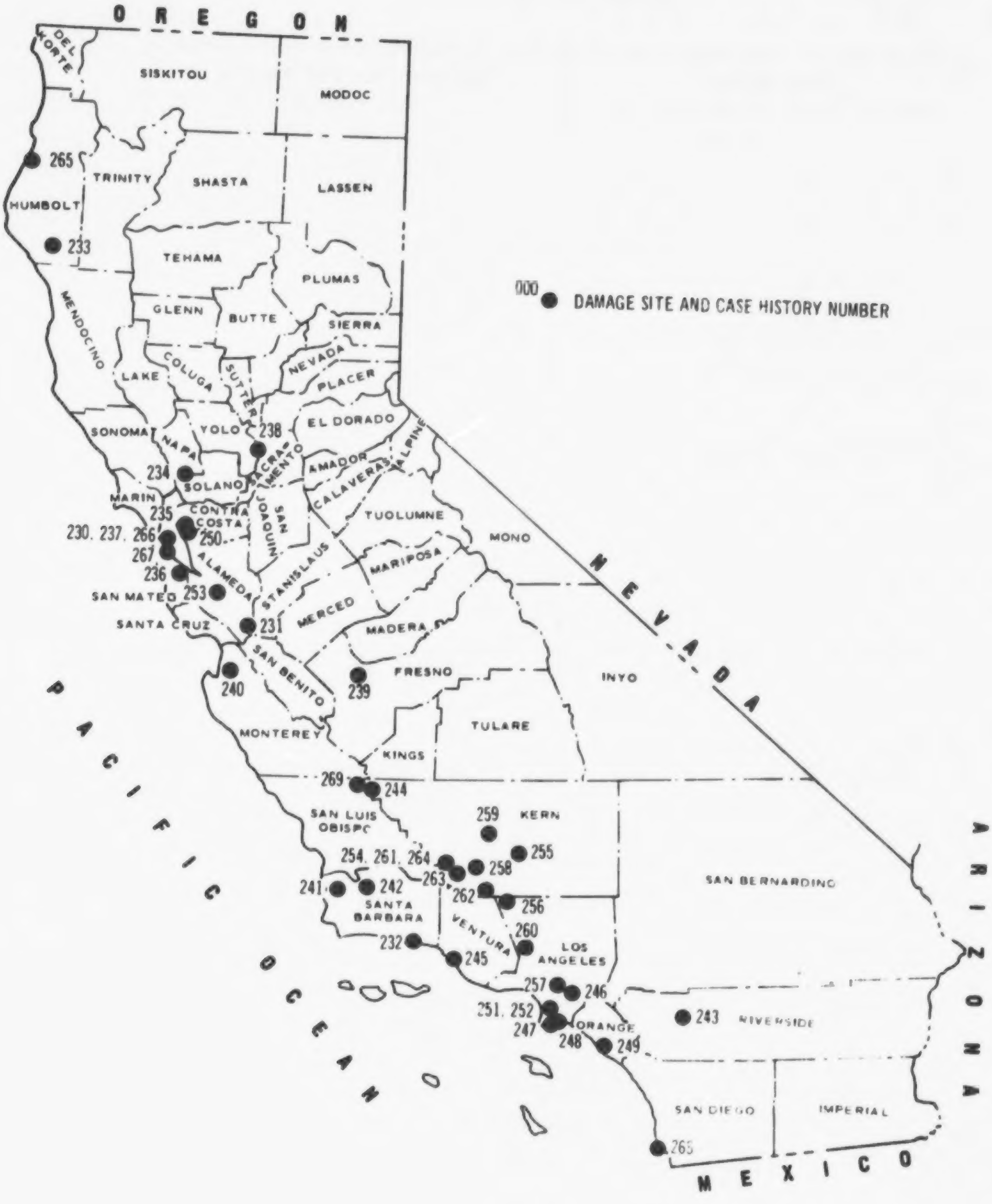
Year	Locality	Damage
1886	Charleston, S.C.	$23,000,000
1898	Mare Island, California	1,400,000
1906	San Francisco, California	24,000,000
	Fire Loss	350,000,000
1925	Santa Barbara, California	8,000,000
1933	Long Beach, California	40,000,000
1935	Helena, Montana	4,000,000
1940	Imperial Valley, California	6,000,000
1941	Torrance-Gardena, California	1,000,000
1944	Cornwall, Canada-Massena, N. Y.	2,000,000
1946	Hawaii (Tsunami damage from earthquake in Aleutians)	25,000,000
1949	Puget Sound, Washington	25,000,000
1949	Terminal Island, California (oil wells only)	9,000,000
1951	Terminal Island, California (oil wells only)	3,000,000
1952	Kern County, California	60,000,000
1954	Eureka-Arcata, California	2,100,000
1954	Wilkes-Barre, Pennsylvania	1,000,000
1955	Terminal Island, California (oil wells only)	3,000,000
1955	Oakland-Walnut Creek, California	1,000,000
1957	Hawaii (Tsunami damage from earthquake in Aleutians)	3,000,000
1957	San Francisco, California	1,000,000
1959	Hebgen Lake, Montana (damage to timber and roads)	11,000,000
1960	Hawaii and west coast of United States (Tsunami damage from earthquake off the cost of Chile)	25,500,000
1961	Terminal Island, California (oil wells only)	4,500,000
1964	Alaska and west coast of United States (Tsunami damage from earthquake near Anchorage, Alaska; includes earthquake damage in Alaska)	500,000,000
1965	Puget Sound, Washington	12,500,000
1969	Santa Rosa, California	6,000,000
1971	San Fernando, California	500,000,000

Table G-3. Expectation of Earthquakes in California (150,000 mi^2) (from Housner, 1970)

Magnitude	Number Per 100 Years
4.75 - 5.25	250
5.25 - 5.75	140
5.75 - 6.25	78
6.25 - 6.75	40
6.75 - 7.25	19
7.25 - 7.75	7.6
7.75 - 8.25	2.1
8.25 - 8.75	0.6

Table G-4. Percent Probability of Acceleration at a Location in California (from Housner, 1970)

Acceleration (% g)	In Period of Years			
	10	25	50	100
5	65	92	99	99
10	37	70	88	98
15	19	41	65	87
20	10	43	40	63
25	5	12	22	37
30	2.5	5.5	10	19
35	1.0	2.5	4.4	8.7


000 ● DAMAGE SITE AND CASE HISTORY NUMBER
OREGON
NEVADA
ARIZONA
MEXICO
PACIFIC OCEAN
DEL NORTE
SISKITOU
MODOC
HUMBOLT
TRINITY
SHASTA
LASSEN
TEHAMA
PLUMAS
GLENN
BUTTE
SIERRA
MENDOCINO
LAKE
COLUGA
SUTTER
NEVADA
PLACER
SONOMA
NAPA
YOLO
SACRAMENTO
EL DORADO
ALPINE
AMADOR
CALAVERAS
SOLANO
MARIN
CONTRA COSTA
SAN JOAQUIN
TUOLUMNE
MONO
ALAMEDA
STANISLAUS
MARIPOSA
SAN MATEO
MERCED
MADERA
SANTA CRUZ
SAN BENITO
FRESNO
INYO
MONTEREY
TULARE
KINGS
SAN LUIS OBISPO
KERN
SAN BERNARDINO
SANTA BARBARA
VENTURA
LOS ANGELES
ORANGE
RIVERSIDE
SAN DIEGO
IMPERIAL
265
233
238
234
235
230, 237, 266
250
267
236
253
231
240
239
269
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259
255
254, 261, 264
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251, 252
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268

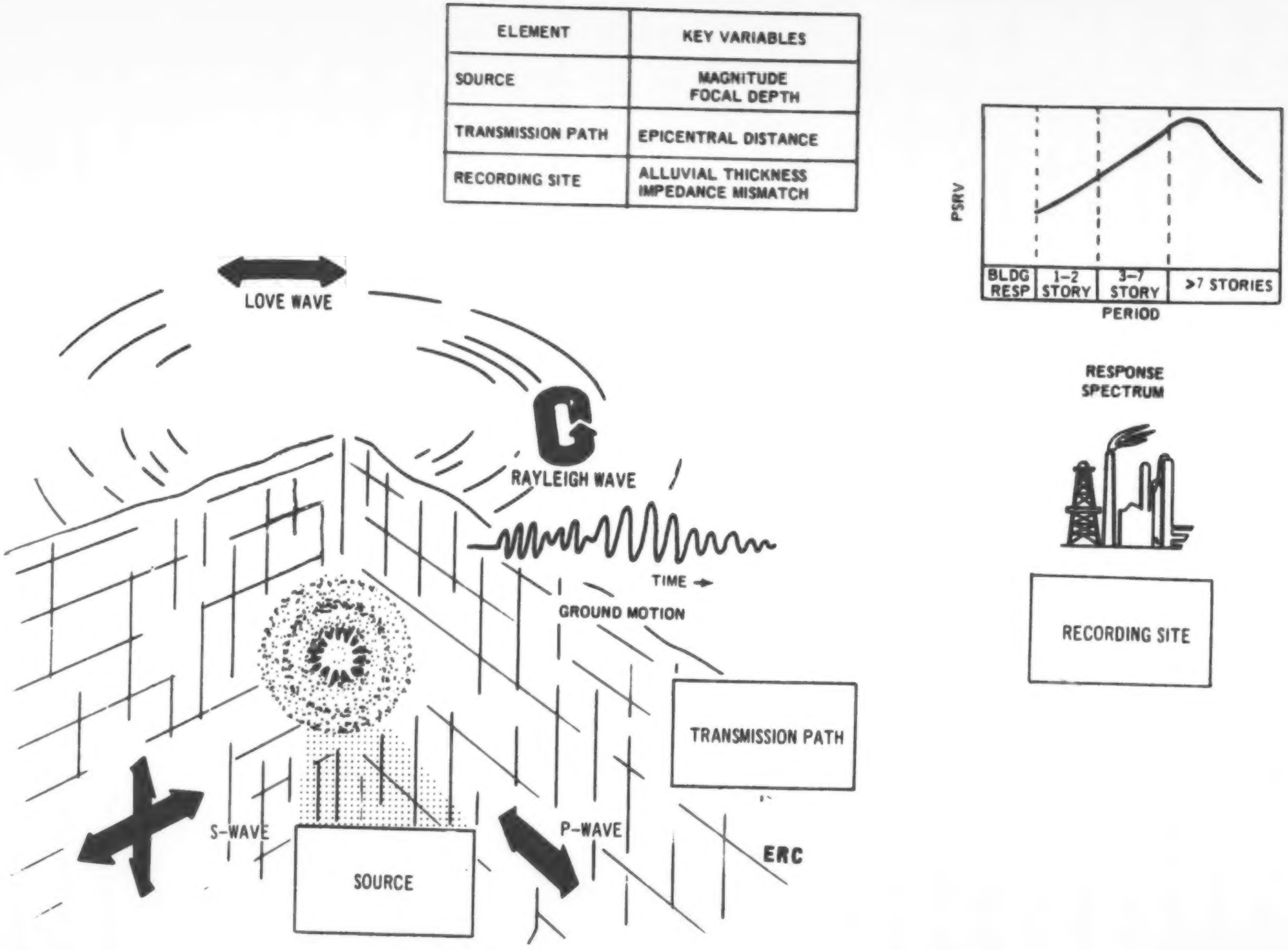
Figure G-5. Earthquake Damage to Petroleum Systems

The San Fernando earthquake of February 9, 1971, was extremely destructive in spite of its moderate 6.4 magnitude. Accelerations in excess of 1 g were recorded in the epicentral region. Oil and gas installations in the Los Angeles area escaped severe damage (Moran, 1972). Pauley Petroleum's Newhall refinery, located about 10 miles northwest of the epicenter of the quake, was forced to shut down temporarily because of damage to storage tanks and pipelines. Other refineries in the Los Angeles area apparently suffered only minor damage. Most producing oil fields in the area shut down immediately after the earthquake and returned to production a few days later. Severe damage was sustained by gas lines in a 4-square mile area in the northeast corner of San Fernando Valley. Eight supply lines were sufficiently damaged to necessitate removal from service.

During the San Fernando earthquake an unprecedented amount of strong ground motion data was obtained. These data will enable significant engineering studies correlating earthquake ground motion, petroleum system structural response, and damage to be made for the first time. This work is now in progress.

Figure G-6 illustrates schematically the important elements of the earthquake ground motion hazard to petroleum systems. The ground motion from an earthquake has a complex relationship with the magnitude and focal depth of the energy release, the epicentral distance along which the body (P and S) and surface (Rayleigh and Love) waves travel, and the physical characteristics of the soil profile at the site of the petroleum system of interest. The response spectrum (e.g., pseudorelative velocity or PSRV) characterizes the spectral composition of the earthquake ground motion. Response spectra have an additional value in that they can be related to structural response and damage.

Figure G-7 illustrates representative 5-percent damped PSRV spectra derived from strong motion accelerographs recording the San Fernando earthquake. These spectra represent a distance range of about 85 miles and peak horizontal acceleration loads ranging from 0.01 to 1.2 g. Various petroleum fields are listed along the margin of Figure G-7 relative to the response spectrum depicting the ground motion exposure


LOVE WAVE
RAYLEIGH WAVE
TIME →
GROUND MOTION
TRANSMISSION PATH
S-WAVE
SOURCE
P-WAVE
ERC
PSRV
BLDG RESP
1–2 STORY
3–7 STORY
>7 STORIES
PERIOD
RESPONSE SPECTRUM
RECORDING SITE

ELEMENT	KEY VARIABLES
SOURCE	MAGNITUDE FOCAL DEPTH
TRANSMISSION PATH	EPICENTRAL DISTANCE
RECORDING SITE	ALLUVIAL THICKNESS IMPEDANCE MISMATCH

Figure G-6. Illustrations of the Earthquake Ground Motion Hazard

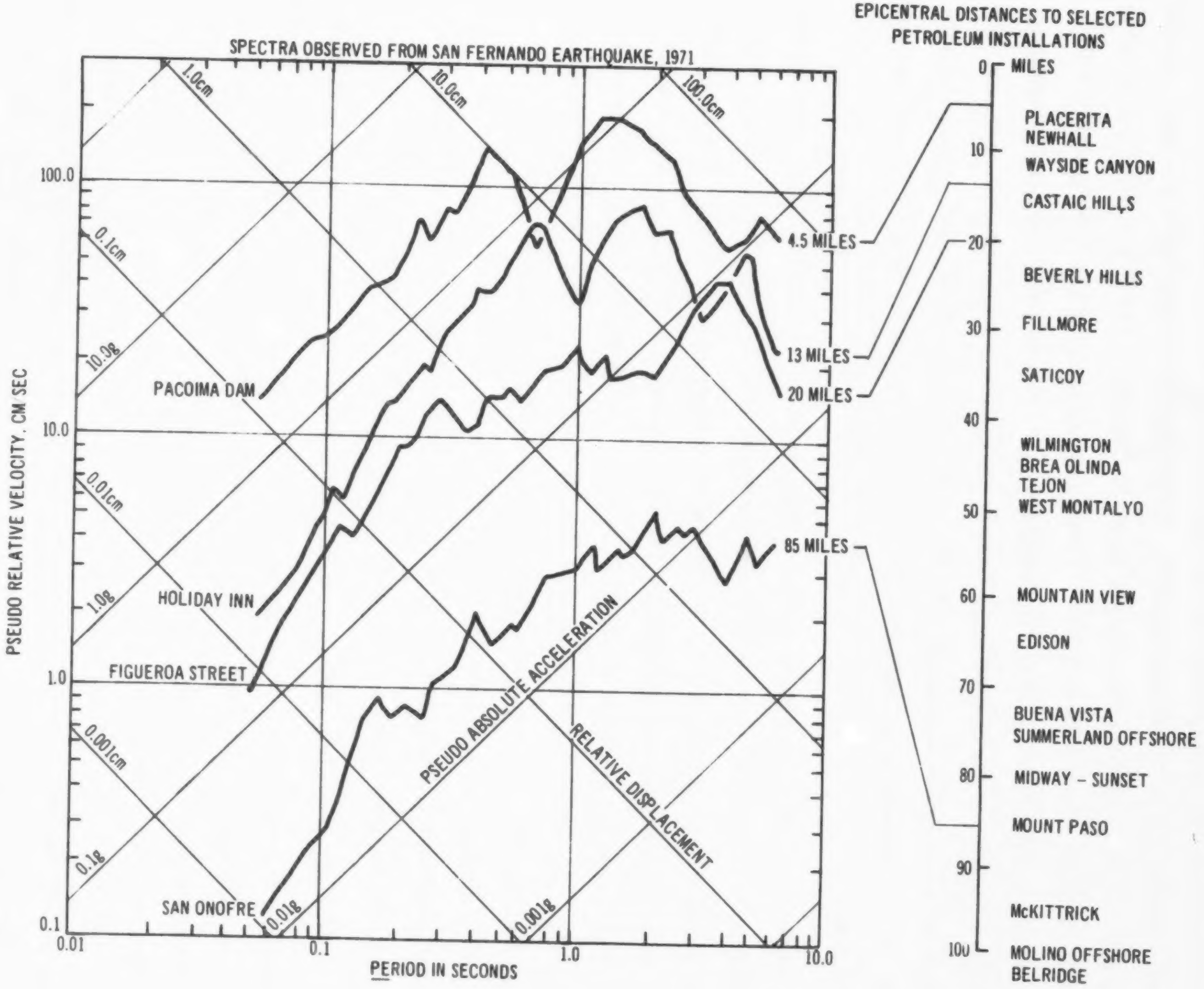
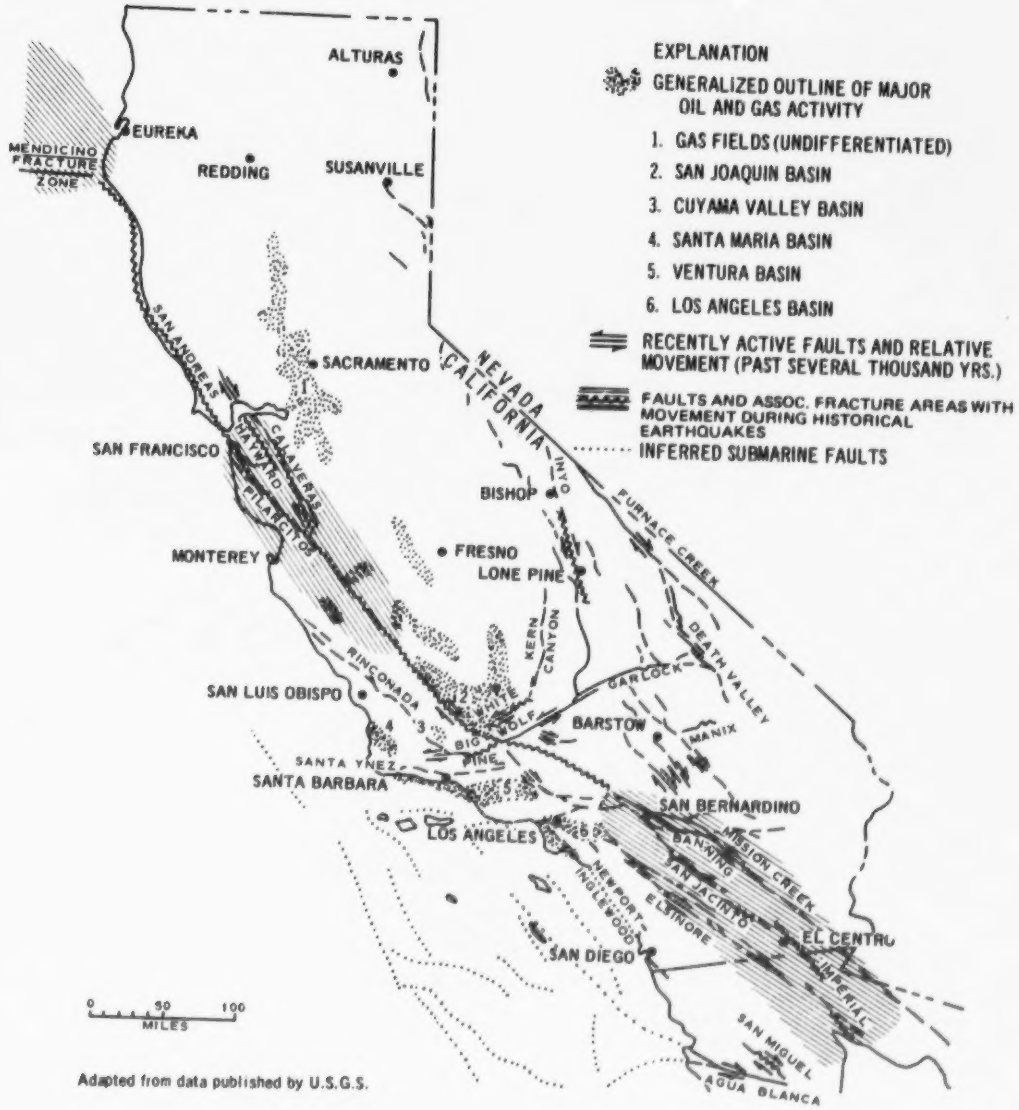


Figure G-7. Observed Response Spectra, San Fernando Earthquake (1971) they received. Figure G-8 depicts a map view of the major California petroleum fields relative to the major fault systems (potential sources of future earthquakes) and the epicenter of the San Fernando earthquake. An earthquake of magnitude 6.4 can reasonably be expected to occur about once every 4 years in California and on practically any one of the fault systems shown (Allen, 1972). Furthermore, many of the fault systems will sustain larger magnitude quakes. The time interval between two successive magnitude 7 quakes anywhere on the San Andreas fault is estimated as 15 years and the recurrence interval for two magnitude 8 quakes is 100 years (Wallace, 1970). A destructive earthquake, occurring nearer to California petroleum systems could have significant environmental impact.

The entire Alaska region is in an active earthquake zone (see Figure G-9). The Alaskan earthquake of March 27, 1964, with Richter magnitude 8.5, is the most recent and profound example of the havoc that an earthquake can cause in this region. The epicenter was about 75 miles east of Anchorage. The quake occurred along a fault rupture about 400 miles in length, released about twice as much energy as the 1906 San Francisco earthquake, and was felt over an area of almost 500,000 square miles. In addition, some 7500 aftershocks occurred along a belt 480 miles long and 150 miles wide. Some 125 people died as a consequence of the earthquake and aftershock sequence, and total estimated damage of about $500 million (recently updated) was sustained. Loss of life and property would have been far greater if Alaska had been more densely populated.

Prior to the San Fernando 1971 earthquake, the Alaskan earthquake was the best documented and most thoroughly studied earthquake in history. Detailed engineering studies of the damage were made (see Steinbrugge, 1967, for details). Among other facts, these studies showed that oil storage tanks were vulnerable to earthquake forces. Seven oil company tanks in Anchorage collapsed, with one releasing 750,000 gallons of aviation fluid (Housner, 1970). Oil storage tanks at Valdez, Seward, Kodiak, and Whittier ruptured and burned (National Academy of Sciences, 1969). Landslides broke gas distribution lines in at least 120 places but only a single leak developed in the 95-mile line that transmits natural gas from fields near Kenai to Anchorage (Eckel, 1967). Damage


EXPLANATION
GENERALIZED OUTLINE OF MAJOR OIL AND GAS ACTIVITY
1. GAS FIELDS (UNDIFFERENTIATED)
2. SAN JOAQUIN BASIN
3. CUYAMA VALLEY BASIN
4. SANTA MARIA BASIN
5. VENTURA BASIN
6. LOS ANGELES BASIN
RECENTLY ACTIVE FAULTS AND RELATIVE MOVEMENT (PAST SEVERAL THOUSAND YRS.)
FAULTS AND ASSOC. FRACTURE AREAS WITH MOVEMENT DURING HISTORICAL EARTHQUAKES
INFERRED SUBMARINE FAULTS
ALTURAS
EUREKA
MENDICINO FRACTURE ZONE
REDDING
SUSANVILLE
SAN ANDREAS
SACRAMENTO
NEVADA
CALIFORNIA
SAN FRANCISCO
CALAVERAS
HAYWARD
PILARCITOS
INYO
BISHOP
FURNACE CREEK
MONTEREY
FRESNO
LONE PINE
KERN CANYON
DEATH VALLEY
RINCONADA
GARLOCK
SAN LUIS OBISPO
WHITE WOLF
BARSTOW
MANIX
BIG PINE
SANTA YNEZ
SANTA BARBARA
SAN BERNARDINO
LOS ANGELES
BANNING
MISSION CREEK
SAN JACINTO
NEWPORT-INGLEWOOD
ELSINORE
EL CENTRO
IMPERIAL
SAN DIEGO
SAN MIGUEL
AGUA BLANCA
0 50 100
MILES

Adapted from data published by U.S.G.S.

Figure G-8. Locations of Major California Oil and Gas Fields in Relation to Active Faults

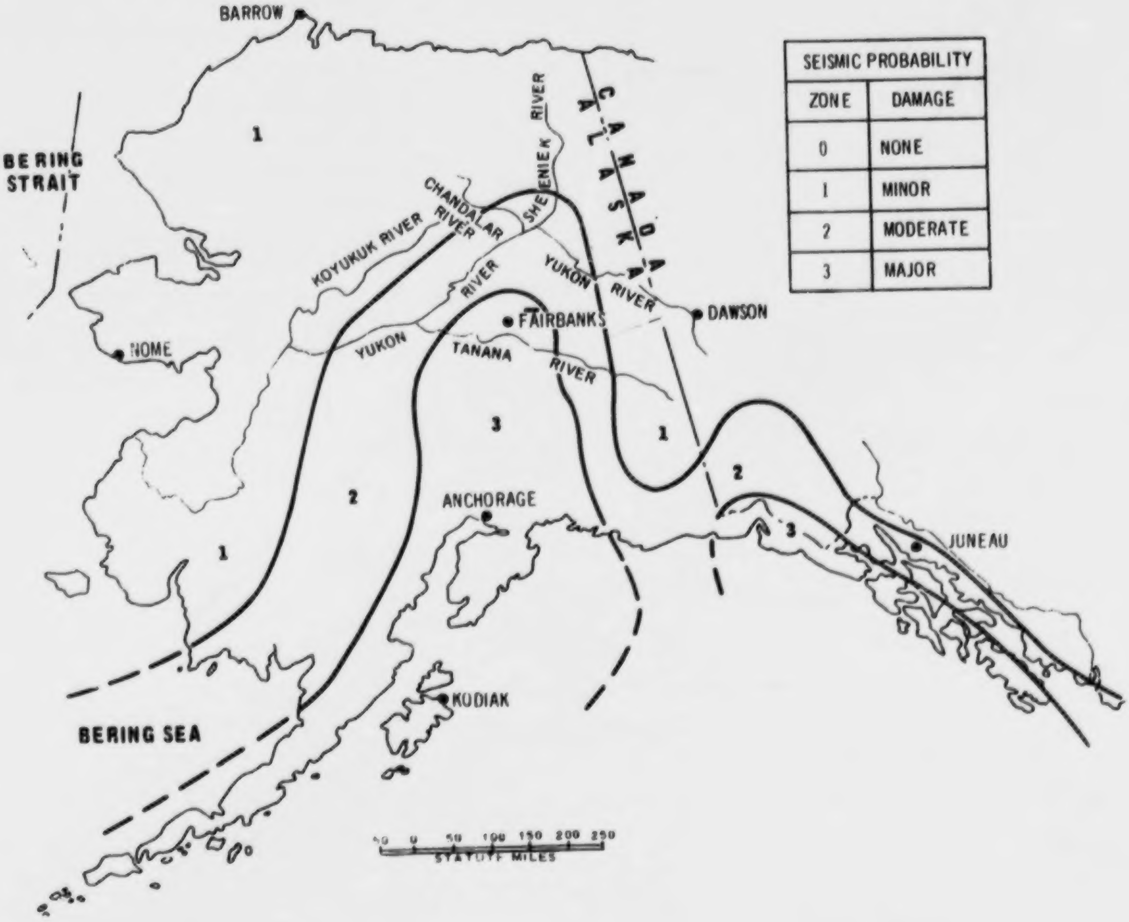

BARROW
BERING STRAIT
NOME
KOYUKUK RIVER
CHANDALAR RIVER
SHEENJEK RIVER
CANADA
ALASKA
YUKON RIVER
YUKON
RIVER
FAIRBANKS
TANANA RIVER
DAWSON
ANCHORAGE
JUNEAU
KODIAK
BERING SEA
1
1
2
3
1
2
3
SEISMIC PROBABILITY
ZONE DAMAGE
0 NONE
1 MINOR
2 MODERATE
3 MAJOR
50 0 50 100 150 200 250
STATUTE MILES

Figure G-9. Seismic Zone Map, Alaska

to the 120-mile-long gas distribution system within Anchorage amounted to nearly $1 million. It is estimated that the approximately 5 minutes of shaking caused by the earthquake in Anchorage aged the gas transmission lines by about 30 years.

No strong motion seismic instrument network was in operation in Alaska at the time of the earthquake, therefore no records of the strong ground motion are available. Observers in Anchorage have provided information suggesting that the maximum horizontal accelerations in Anchorage were about 16 percent g and of very long duration (4 to 7 minutes, according to Steinbrugge, 1970). Clough (1966) suggested that the Taft (1952) response spectrum is representative (except for durations) of the ground motions sustained in Anchorage. Figure G-10 shows the estimated 5-percent damped horizontal ground motion response spectra for the Alaska earthquake at epicentral distances corresponding to Valdez, Anchorage, Kenai, and Kodiak. Petroleum systems are listed in the right margin of Figure G-10 relative to the response spectrum representing their estimated ground motion exposures.

It is of some interest to relate the estimated Alaskan 1964 earthquake response spectra to the petroleum systems at Cook Inlet and to the proposed Alyeska pipeline. Figures G-11 and G-12, respectively, depict the proposed pipeline route superimposed on the structural map of the State and the major oil and gas fields in the Cook Inlet area. The proposed 800-mile pipeline project will carry oil from Prudhoe Bay on the Arctic Ocean to the port of Valdez on the Gulf of Alaska. The proposed pipeline crosses three major mountain systems (Chugach, Alaska, and Brooks), over 350 streams and rivers, and several areas known to be earthquake-prone.

The earthquake problems in California and Alaska are important considerations of potential oil spills from offshore petroleum structures and systems. Ground motions caused by an earthquake transmit motions to a structural system through its foundation. This accelerated movement from an at-rest position causes the structural system to be loaded by inertial forces which are a function of its flexibility, mass, and damping characteristics. Offshore structures are typically constructed of large diameter tubes interconnected by underwater bracing and held in position by piling driven into the bottom. Such structures,

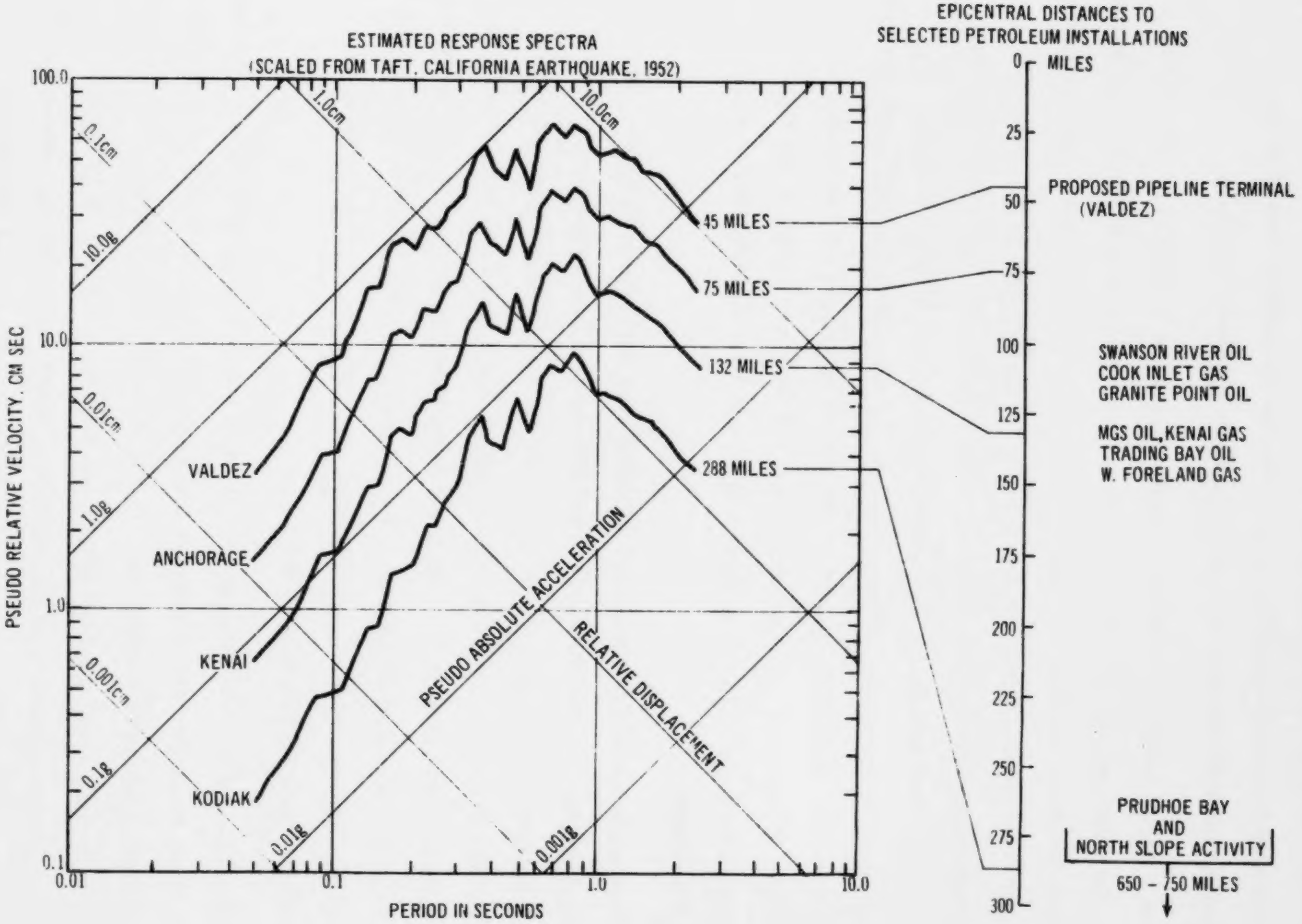


Figure G-10. Estimated Response Spectra, Alaska Earthquake (1964)

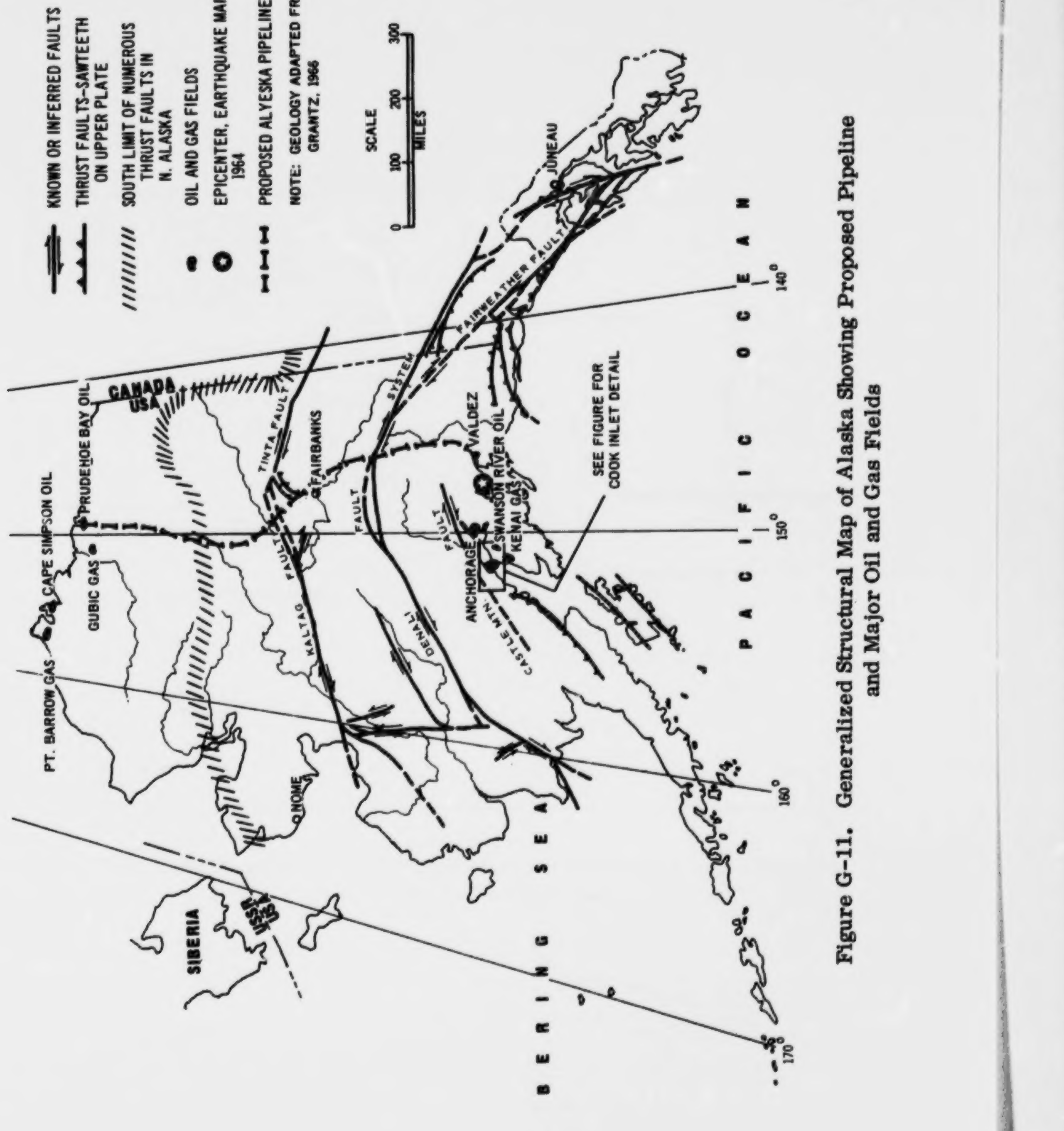

KNOWN OR INFERRED FAULTS
THRUST FAULTS-SAWTEETH ON UPPER PLATE
SOUTH LIMIT OF NUMEROUS THRUST FAULTS IN N. ALASKA
OIL AND GAS FIELDS
EPICENTER, EARTHQUAKE MAR 27, 1964
PROPOSED ALYESKA PIPELINE
NOTE: GEOLOGY ADAPTED FROM GRANTZ, 1966
SCALE
0
100
200
300
MILES
PT. BARROW GAS
CAPE SIMPSON OIL
PRUDHOE BAY OIL
GUBIC GAS
CANADA
USA
SIBERIA
USSR
USA
NOME
KALTAG
FAULT
TINTA FAULT
FAIRBANKS
DENALI
FAULT
SYSTEM
FAULT
FAIRWEATHER FAULT
ANCHORAGE
CASTLE MTN.
FAULT
SWANSON RIVER OIL
KENAI GAS
VALDEZ
JUNEAU
SEE FIGURE FOR COOK INLET DETAIL
BERING SEA
PACIFIC OCEAN
170°
160°
150°
140°

Figure G-11. Generalized Structural Map of Alaska Showing Proposed Pipeline and Major Oil and Gas Fields

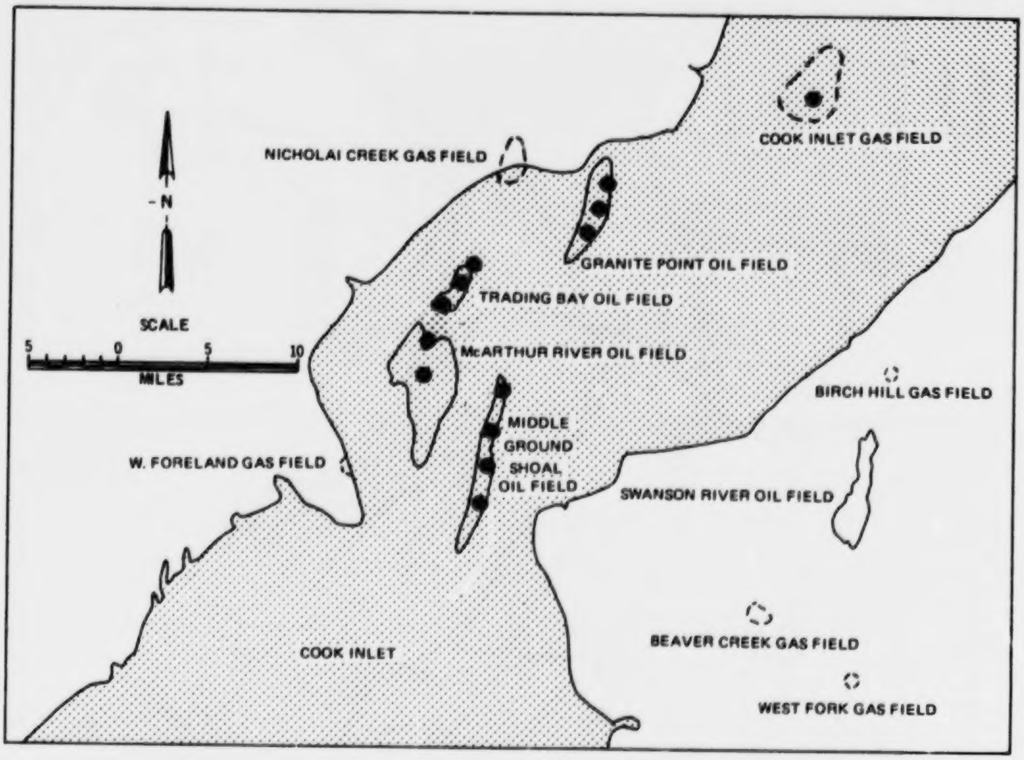

N
SCALE
5
0
5
10
MILES
NICHOLAI CREEK GAS FIELD
COOK INLET GAS FIELD
GRANITE POINT OIL FIELD
TRADING BAY OIL FIELD
McARTHUR RIVER OIL FIELD
BIRCH HILL GAS FIELD
MIDDLE GROUND SHOAL OIL FIELD
W. FORELAND GAS FIELD
SWANSON RIVER OIL FIELD
BEAVER CREEK GAS FIELD
COOK INLET
WEST FORK GAS FIELD

Figure G-12. Generalized Oil and Gas Field Locations, Cook Inlet Area (See Figure G-11 for location)

if standing in air and oscillating, would experience resonant strain amplitudes limited only by structural damping. Offshore structures, however, are partially immersed in water with foundation piles driven into saturated soil. As the submerged parts of a structure are forces to follow the earthquake motions, some water in the vicinity of the structural members will also move. This water, which associates itself with the structure during acceleration, increases the virtual mass of the members and thus increases the local inertial loads. As a direct consequence of this added mass effect, the mode shapes of a structure in water are changed and the natural frequencies of the structure are lowered. Another difficult and poorly understood problem is the behavior of saturated foundation soils and piling during an earthquake. Sea floor slides also represent potential hazards to petroleum systems. The performance of petroleum structural systems under strong earthquake loads has not yet been fully tested or studied. As a result, engineering data are insufficient to reduce uncertainty and to validate present design techniques and theories.

G.2.3 Tsunamis

Tsunamis are destructive water waves with periods in the range of 5 to 60 minutes or longer. They are created by a number of mechanisms (Wiegel, 1970). The Pacific Ocean basin, a zone of high seismicity, is subject to more tsunamis than any other region. These waves attain destructive proportions in the immediate vicinity of their origin and travel across an ocean at speeds as great as 600 miles an hour and reaching heights of 50 feet or more by the time they reach shore.

Well-established early warning systems have been developed to signal the development and occurrence of a tsunami. Many tsunamis have been measured and catalogued; however, few have caused extensive spill damage to petroleum systems, primarily because of the early warning systems.

One of the most devastating tsunamis was generated by theAlaskan earthquake of March 27, 1964, (Grantz, et al, 1964; Wilson and Torum, 1968). It caused major damage in a number of Alaskan coastal towns. The tsunami propagated across the eastern Pacific Ocean and subsequently caused damage estimated at $11 million at Cresent City, California (Griffin, et al, 1964). Oil storage tanks in Crescent City caught fire as a consequence of the tsunami. The catastrophic nature of this natural hazard requires continuing study to minimize potential future environmental impact.

Dr. William Pecora, formerly Director of U.S. Geological Survey and Undersecretary of Interior, estimated that there are 50 billion barrels of oil (five times the minimum estimate given for the North Slope) near and under the Gulf of Alaska in the Cordova area (see article, Gulf of Alaska - Richer than the North Slope?, Oceanology, pp. 11-12, February, 1972). Although these estimated figures are potential and no oil has actually been discovered, there is a critical need to continue monitoring tsunamis and the resultant effects of petroleum systems in order to prepare an adequate data base for future use.

G.2.4 Waves and Currents

In the search for and the development of petroleum reserves, many new and difficult engineering problems have been encountered. This is particularly true for Cook Inlet, Alaska, a relatively large body of water approximately 170 miles long by 45 miles wide. Cook Inlet has one of the largest tidal ranges in the world (from 20 to 30 feet) occasionally even creating a "tidal bore." In addition, the tidal currents are relatively swift (4 to 7 knots). Storms frequently generate 10- to 15-foot waves and winds reach 80 miles per hour. Air temperatures range from 80° F to -40° F. Water temperatures range from a high of about 55° F to a low of 29° F. These environmental conditions significantly affect the design and operation of petroleum systems (platforms, submarine pipelines, production facilities, and tanker loading terminals) in Cook Inlet.

Currents of the magnitude experienced in upper Cook Inlet have had a particularly significant effect on pipelines installed on the Inlet floor (Goepfert, 1969). The environmental forces acting on a submerged pipeline are considerably different for buried and unburied systems. It is generally acknowledged that the hazards encountered by a pipeline laid across the bottom are much more serious than those encountered by a buried pipeline (Ralston and Herbich, 1969). Burial of the pipeline generally affords the best protection from the effects of waves and currents. However, burying pipelines is expensive and, in some locations, difficult or impossible because of rocky bottom conditions or the presence of reefs. Even when burial is feasible, scour, flutter, and differential buoyancy along sections of the pipeline often create severe mechanical problems.

Several pipeline failures have been experienced in Cook Inlet (Goepfert, 1969). These appear to correlate with the peak tidal range period and to be the direct result of flutter. Flutter occurs when the frequency of vortices shedding in the wake of a stationary body in a moving current field approaches the natural frequency of the body. The shedding of vortices must occur in a regular frequency on alternate sides of the body to establish alternating forces which induce motion perpendicular to the current direction (see Figure G-13). It is the alternating vertical force which causes flutter. As the frequency of the alternating forces approaches the natural frequency of the suspended pipe segment, deflections rapidly and violently reach destructive proportions.

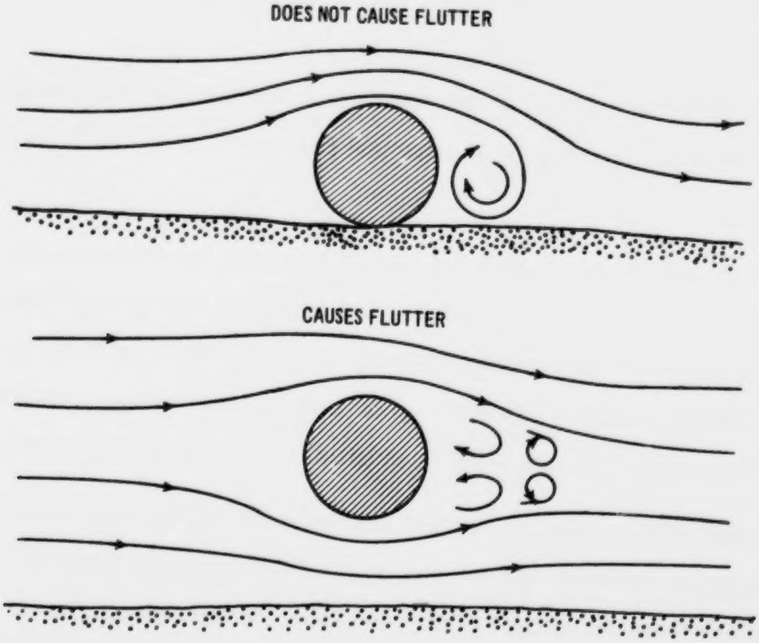


Figure G-13. Schematic Current Flow Around a Pipe

Blumberg (1964 a, b, c, d, e, f) has reported numerous failures involving drilling, production, and pipeline facilities in the Gulf Coast during the hurricanes of 1961, 1964, and 1965. He reported that losses sustained off the Louisiana Coast along during 1964 and 1965 exceeded $200 million. Significant ocean wave and current effects were noted to extend to depths of at least 240 feet, a finding which has a bearing on the design of deep water petroleum systems.

G.2.5 Ice

The establishment and operation of petroleum systems in geographic areas susceptible to ice and/or heavy winter storms presents a potential oil spill problem. Cook Inlet, Alaska, is one example of an area subject to the hazardous ice environment. Petroleum systems are exposed to three types of fresh water or salt water ice environment, all of which are potentially hazardous:

1. The open ocean or coast where ice fields and bergs are encountered.
2. Tidal bays, inlets, or estuaries where ice may be in the form of bergs or fields.
3. A harbor fed by a major fresh water source where ice may be formed locally or fresh water ice may be discharged from a river in the form of floes or ice jams.

Offshore structures will not normally be subject to static ice forces of the type that can develop in sheltered bodies of water because the action of waves and tides will usually prevent large ice sheets from adhering directly to a petroleum system structure. It is not uncommon, however, for ice to build up on a structural member in the tidal zone, causing dangerous vertical forces such as uplift at high tide and dead load at low tide.

Floating ice moving with a wind or current will often be rafted into multiple thicknesses as a result of impacts and wind-driven packing. Forces on maritime structures from moving ice may act from directions other than those of the principal current directions. Thus, a petroleum system structure must be designed to resist ice forces from all directions. Moving ice sheets present a serious problem since they can cause forced vibrations of the structure. These forced vibrations are a function of the ice thickness, rate of loading and ice temperature (Peyton, 1968; Geminder, 1968; Matlock, et al, 1969). Dynamic forces resulting from ice force oscillations are transmitted through steel platform structures to derricks, booms, walkways, and other ancillary equipment located on the platform. These structures are not damped by ice and water and thus may oscillate at destructive amplitudes.

The extremes faced by petroleum systems in an environment subject to ice conditions pose severe operational problems as well as potential environmental hazards. Additional experience and data are needed to develop and ensure sound oil pollution control systems for operations in this environment. Data from instrumented petroleum systems (such as the Union Oil Company monopod platform in Cook Inlet) are needed to validate and improve design techniques.

G.2.6 Tornadoes

Tornadoes occur principally in the central United States, from northern Texas to Wisconsin. Approximately 650 tornadoes struck the United States in 1970. These storms strike suddenly and cause widespread devastation in a somewhat unpredictable manner. The Lubbock Storm of May 11, 1970, (Thompson et al, 1970) illustrates this type of natural hazard. Within 1 hour, the storm killed 26 people, injured more than 2000, and damaged or destroyed property to the extent of $135 million. It directly affected approximately one-fourth of the city. Few, if any, oil spills have been directly attributable to tornadoes, although the potential to cause damage to storage tanks is great.

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ATTACHMENT 1 TO APPENDIX G
EARTHQUAKE DAMAGE TO PETROLEUM STRUCTURES

(Source: Department of Water Resources State of California)

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
230	San Francisco, San Francisco County - 50 miles from epicenter	Santa Cruz Mtns October 8, 1865	Gas Pipes
	"On the marshy lands in the vicinity of Howard and Seventh Streets, lamp posts, water pipes, and gas pipes were broken and thrown out of position." Holden, p. 66.		
231	Gilroy, Santa Clara County - about 8 miles from epicenter	Monterey Bay Region Earthquake April 24, 1890	Gas Mains
	"The gas mains were disjointed, and there was some other damage." Townley and Allen, 1939, p. 81.		
232	Santa Barbara, Santa Barbara County, 10 mi from epicenter	Los Alamos earthquake July 27, 1902	Oil and Water Pipelines
	"On the property of the Western Union Oil Co., two tanks containing 3000 barrels of oil each were destroyed. Pipes for conducting oil and water were twisted and broken." Townley and Allen, 1939, p. 117.		
233	Briceland, Humboldt County, 150 miles from epicenter	San Francisco earthquake April 18, 1906	Gas Pipes
	"The village suffered damage to the extent of $1500 due to the breaking of chimneys, water and gas pipes, household furniture, etc." Lawson, Vol. 1, p. 170.		

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
234	Napa, Napa County 33 miles from epicenter	San Francisco earthquake April 18, 1906	Gas Mains
	"The damage to street gas mains at Napa was very slight, only two leaks developing. The gas station was badly shaken up; about 10 feet of the end wall of the brick building was thrown down, falling on top of the boiler and breaking off the steam pipes. The gas-holders were badly shaken up. Water was displaced from the tanks, but only one guide wheel was shaken out of place." Lawson, Vol. 1, p. 211.		
235	Oakland, Alameda County - 34 miles from epicenter	San Francisco earthquake April 18, 1906	Gas Mains
	"There were very few breaks in cast-iron gas mains. Two of these were caused by impact of heavy debris falling from buildings and poles. One was on Washington Street, where heavy blocks of sandstone fell from the third story and the roof, breaking the main 30 inches below the bituminous rock. Another was at the corner of Fourteenth Street and Broadway, where a transformer fell from a pole, striking the center of a short car rail and bending up both ends. A 3-inch cast iron main a short distance from this was broken at right angles. On the Twelfth Street Dam, a cast iron pipe was broken and displaced over a foot while the high pressure steel pipe paralleling it was practically undisturbed." Lawson, Vol. 1, p. 302.		
236	Redwood City, San Mateo County - 47 miles from the epicenter	San Francisco earthquake April 18, 1906	Gas Tank
	"A 20,000-foot gas-holder in a redwood tank above ground was completely demolished by the earthquake." Lawson, p. 254.		

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
237	San Francisco, San Francisco County - approximately 32 miles southeast of epicenter	San Francisco earthquake April 18, 1906	Gas Mains
	"In solid ground there was very little trouble and very few breaks. A number of the breaks noted ... as being on solid ground were caused by the use of dynamite and other explosives, employed in blowing down buildings. "In the above sunken streets the city sewers, as well as other conduits such as gas pipes, electric light conduits, etc., suffered the same as the water pipes in that they were similarly ruptured by the sinking and violent oscillations of the ground. "During the three-month period from April 18 to July 18, 1906 ... 300 breaks in the pipe system had been discovered and repaired, 276 of which were in or immediately adjoining the burnt district. In the unburnt district, only 24 breaks have been found and repaired." Eckart, pp. 194-195.		
238	Sacramento, Sacramento County - 75 miles east of epicenter	San Francisco earthquake April 18, 1906	Gas Tank
	"The damage at the gas plant was very slight. The gas holders rocked to such an extent that considerable water was thrown out of the tanks and the seals of the holder sections were partially emptied, allowing gas to escape." Lawson, p. 216.		
239	Mendota, Fresno County - 156 miles from epicenter	San Francisco earthquake April 18, 1906	Oil Tank
	"At an oil-pumping station 10 miles south of Mendota, there were ten large tanks ... Of these, the roofs (unsubstantially braced) of six caved in and much oil was thrown over the sides." Lawson, p. 318.		

<table>
<tr><th>Case No.
(See Figure G-5)</th><th>Location</th><th>Earthquake</th><th>Petroleum System Damaged</th></tr>
<tr><td>240</td><td>Salinas River, Monterey County - 120 miles from epicenter</td><td>San Francisco earthquake
April 18, 1906</td><td>Oil Pipeline</td></tr>
<tr><td></td><td colspan="3">"An oil pipe which crossed the bridge was twisted and buckled at the south end of the bridge, and when this was repaired the pipe was found to be shortened 7 feet. The pipeline extends from the San Joaquin Valley to the Bay of Monterey. A few hundred yards south of the bridge is a pumping station, at which point some of the connections of the pipe were broken and displaced. The direction of the shortening of the bridge span and the pipe is roughly normal to the direction of the San Andreas Rift, on the other side of the Gavilan Range. Mr. S. A. Guiberson, superintendent of the line, reports that the pipe was broken in about 20 places in the vicinity of the river, and that at some of these breaks the pipe was pulled apart." Lawson, Vol. 1, p. 296.</td></tr>
<tr><td>241</td><td>Harris, Santa Barbara County - 15 miles from epicenter</td><td>Los Alamos earthquake
January 11, 1915</td><td>Oil Pipeline</td></tr>
<tr><td></td><td colspan="3">"At Harris, the 8-inch pipeline of the Associated Oil Company from the Santa Maria field to Gaviota was broken and about 1200 barrels of oil escaped." Beal, March 1915, p. 19.</td></tr>
<tr><td>242</td><td>Santa Rita, Santa Barbara County - 10 miles from epicenter</td><td>Los Alamos earthquake
January 11, 1915</td><td>Oil Pipeline</td></tr>
<tr><td></td><td colspan="3">"The same pipe (as in Case 241 above) was broken in two places near Santa Rita where the line runs southeast; in one of these breaks the pipe was apparently pulled apart at the union, and the southeast section pushed to the southwest and both sections pushed past each other, so that when found one overlapped on the other four or five inches." Beal, March 1915, p. 19.</td></tr>
</table>

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
243	San Jacinto, Riverside County - 3 miles from epicenter	San Jacinto earthquake April 21, 1918	Gas Mains
	"...within ten minutes the breaking of the gas mains made it necessary to shut off the supply." UC, 1915, Vol. 1, p. 130.		
244	Shandon and Antelope Valley, San Luis Obispo and Kern Counties - 10 miles southeast of epicenter	Cholame Valley earthquake March 10, 1922	Oil Pipelines
	"...oil pipelines broken between Shandon and Antelope..." Wood and Heck, 1951, p. 32.		
245	Ventura, Ventura County - 130 miles from epicenter	Point Arguello earthquake November 4, 1927	Oil Pipeline
	"In Ventura a pipeline was broken." UC, 1915-1930, pp. 113-121.		
246	Santa Fe Springs Los Angeles County 15 miles from epicenter	Whittier earthquake July 8, 1929	Oil Pipelines
	"Oil operators at Santa Fe Springs reported that two producing oil wells in the eastern end of the field were stopped up by the tremor. Several oil lines in the field were reported broken." UC, 1915-1930, pp. 170-176.		
247	Signal Hill, Los Angeles County - 5 miles from epicenter	Long Beach earthquake March 10, 1933	Oil Pipeline
	"Oil line broken." USC&GS, 1933, p. 11.		
248	San Pedro, Los Angeles County - 20 miles from epicenter	Long Beach earthquake March 10, 1933	Gas Mains
	"Numerous leaks in gas lines." USC&GS, 1933, p. 12.		

<table>
<tr><th>Case No.
(See Figure G-5)</th><th>Location</th><th>Earthquake</th><th>Petroleum System Damaged</th></tr>
<tr><td>249</td><td>Laguna Beach, Orange County - 20 miles from epicenter</td><td>Long Beach earthquake March 10, 1933</td><td>Gas Mains</td></tr>
<tr><td></td><td colspan="3">"Leaks in...gas mains." USC&GS, 1933, p. 12.</td></tr>
<tr><td>250</td><td>Berkeley, Alameda County - 4 miles from epicenter</td><td>Berkeley earthquake March 8, 1937</td><td>Gas Pipes</td></tr>
<tr><td></td><td colspan="3">"A number of gas lines were pulled apart or snapped off in the Cragmont Avenue and Keith Avenue section. In Berkeley and El Cerrito...a store's window display of about $150 worth of choice liquors was thrown through a large window..." UC, 1934-1937, Clipping from Oakland Tribune, March 8, 1937.</td></tr>
<tr><td>251</td><td>Torrance-Gardena area, Los Angeles County - 2 miles from epicenter</td><td>Torrance-Gardena earthquake November 14, 1941</td><td>Oil and Gas Pipes and Oil Tanks</td></tr>
<tr><td></td><td colspan="3">"In the oil fields two tanks were demolished, two buckled badly, and a 6-inch pipeline broke in four additional places after having broken in one place during the October 21 earthquake. An 8-inch natural gas pipeline burst. Fire was overted in all cases and most of the oil was recovered. Ground cracks were found in several cases near the broken oil line." USC&GS, "U.S. Earthquakes," 1941, p. 17.</td></tr>
<tr><td>252</td><td>Torrance-Gardena Los Angeles County - 0 miles from epicenter</td><td>Torrance-Gardena earthquake November 14, 1941</td><td>Oil Pipeline</td></tr>
<tr><td></td><td colspan="3">"The swaying east-west trembler...snapped oil and pipelines. In one liquor store, 15 thousand dollars' worth of stock was thrown to the cement floor and ruined." USC&GS, "U.S. Earthquakes," 1941, p. 17.</td></tr>
</table>

<table>
<tr><th>Case No.
(See Figure G-5)</th><th>Location</th><th>Earthquake</th><th>Petroleum System Damaged</th></tr>
<tr><td>253</td><td>San Jose, Santa Clara County - 14 miles west of epicenter</td><td>Mount Hamilton area earthquake October 25, 1943.</td><td>Gas Main</td></tr>
<tr><td></td><td colspan="3">"...at San Jose...a small gas main snapped in the Security Building at First and San Fernando Streets." UC, 1943-48, Clipping from San Francisco News, October 26, 1943.</td></tr>
<tr><td>254</td><td>Maricopa area, Kern County - 2 to 4 miles north of epicenter</td><td>Kern County earthquake July 21, 1952</td><td>Oil Pipelines</td></tr>
<tr><td></td><td colspan="3">"Steel pipelines used on conveying petroleum were severed by landslides caused by the earthquake in the vicinity of Grapevine, near Highway 99. Lateral displacement of alluvium in the area north of Highway 166 caused breaks in other oil lines. Several breaks occurred... (in an area about a mile north of Wheeler Bridge). Rupture of lines appeared to take place at points of weakness, as all breaks do not necessarily appear to have occurred in areas of particularly sharp movement. A cumulative compression and stretching effect caused ruptures, especially where the lines curved. These steel lines averaged five-sixteenths of an inch thick and ranged in diameter from 6 to 10 inches. The line to one General Petroleum pumping station, located about 7 miles west of Highway 99 on Highway 166, bends gently to the north approximately 1-1/2 miles north of the station. The pipe at the bend was separated 18 inches. One-half mile to the north, a 4-foot section of an oil line curving gently to the west was first buckled sharply to the west then straightened out before breaking 6 feet further north. In the same vicinity, two pipes on opposite sides of a road striking north-south suffered the opposite kind of action. The line on the east side telescoped approximately 36 inches, while that on the west side pulled apart approximately 55 inches. These lines were about 30 feet apart at points of rupture..." Marliave, 1952, p. 10.

"The General Petroleum Corporation... Emidio Pipe Line Station was probably the most severely shaken and pipe movements at this location in excess of 5 inches were noted. The following is a summary of pipeline breakage in the vicinity of Emidio Pipe Line Station, with distance from Emidio:</td></tr>
</table>

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
254 (Cont'd)	1.375 miles east: Pulled apart, then telescoped. 1.4 miles east: Pulled apart, then telescoped. 6.75 miles west: Line pulled out of collar. .28 miles north: Line crinkled and ruptured. .72 miles north: Pulled apart. .76 miles north: Pulled apart, then telescoped. 1.04 miles north: Weld broke. 1,5 miles north: Pulled apart, then telescoped 42"." Steinbrugge and Moran, 1954, p. 270.		
255	Emidio, Kern County 3 miles from epicenter	Kern County earthquake July 21, 1952	Oil Pipelines
	"Severe damage to General Petroleum Corporation's pipelines. Breaks occurred on 8- and 10-inch lines. One 10-inch pipe telescoped 42 inches." USC&GS, "Abstracts," MSA-75, 1952, p. 19.		
256	Gorman, Los Angeles County - 16 miles from epicenter	Kern County earthquake July 21, 1952	Gasoline Pipeline
	"...a 10-inch gasoline pipeline severed. Gasoline cascaded down cliff." USC&GS, "Abstracts," MSA-75, 1952, p. 23.		
257	Los Angeles, Los Angeles County - 80 miles from epicenter	Kern County earthquake July 21, 1952	Gas Pipe
	"Sixty-eight earthquake-operated gas shutoff valves in schools of the L. A. School District were operated. Hanging space heaters broke gas lines in industrial installation. Excess flow valves operated." USC&GS, "U.S. Earthquakes," 1956, p. 22.		

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
258	Tajon Ranch, Kern County - 10 to 15 miles from epicenter	Kern County earthquake July 21, 1952	Oil Tank
	"...one of a battery of three 1500-barrel (oil) tanks in the Tajon Ranch area...collapsed..." Johnson, p. 222.		
259	Bakersfield, Kern County - 14 miles from epicenter	Kern County earthquake July 21, 1952	Butane Tanks
	"At Paloma Cycling Plant 16 miles southwest of Bakersfield, the shock of the earthquake caused two of the large spherical butane storage tanks to collapse, thereby rupturing lead-in lines and releasing quantities of highly volatile material." Johnson, p. 222.		
260	Newhall, Los Angeles County - 45 miles from epicenter	Kern County earthquake July 21, 1952	Gas Pipeline
	"Press reported a 12-inch gas line broken near the city limits." USC&GS, "U.S. Earthquakes," 1952, p. 22.		
261	Emidio, Kern County - 2 to 4 miles north of epicenter	Wheeler Ridge earthquake January 12, 1954	Gas Pipelines
	"...Southern California Gas and Richfield Oil Company had...pipeline damage...in this area." Steinbrugge and Moran, 1954, p. 270.		
262	Ridge Route between Los Angeles and Taft - 25 miles from epicenter	Wheeler Ridge earthquake January 12, 1954	Gas Pipeline
	"...12-inch gas pipeline broke." USC&GS, 1954, p. 12.		

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
263	Paloma Oil Field, Kern County - 16 miles from epicenter	Wheeler Ridge earthquake January 12, 1954	Oil Pipeline
	"...pipeline cracked at the Paloma oil field." USC&GS, "U.S. Earthquakes," 1954, p. 12.		
264	Maricopa Flats Kern County - 15 miles from epicenter	Wheeler Ridge earthquake January 12, 1954	Gas Pipeline
	"...gas pipelines damaged..." USC&GS, 1954, p. 12.		
265	Eureka, Humbolt County - 12 miles southwest of epicenter	Eureka earthquake December 21, 1954	Gas Pipes
	"The Eureka distribution system was broken in a number of places including 16 gas pipeline breaks and 19 water pipeline breaks." Steinbrugge and Moran, April 1957, pp. 138-139.		
266	San Francisco, San Francisco County - 5 miles from epicenter	Daly City earthquake March 22, 1957	Gas Pipes
	"...gas lines...broken." USC&GS, "U.S. Earthquakes," 1957, p. 23.		
267	San Bruno, San Mateo County - 5 miles from epicenter	Daly City earthquake March 22, 1957	Gas Main
	"Gas main broke in Rollingwood tract...plumbing broken." USC&GS, "U.S. Earthquakes," 1957, p. 22.		

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
268	Fort Rosecrans, Point Loma, San Diego County, approximately 150 miles northeast of epicenter	Baja California earthquake November 30, 1958	Gas Main
	"... Lt. Brown felt it at Fort Rosecrans and the next day discovered a broken water main on the east hill-slope of the Point. There were numerous deep, open ground cracks; a major crack parallel to the contours passed through the site of the pipe break. The pipe ran directly upslope. On December 5 an odor of gas was noted and he found a 2-inch tension break in a gas line northeast of the water line break. There are ground cracks in the vicinity of this break also and one of them passed through the site of the break. It was subsequently discovered that 2-1/2 million cubic feet of gas had escaped, indicating that the break had been open for some days, quite possibly since November 30. I toured the area of damage with Lt. Brown and saw extensive tension cracking high on the hill slope and small compression ridges along the asphalt roadway at the foot of the slope. The cracks progress up the hillside and back down to the roadway, enclosing an area of some acres located between Ballast Point and the U. S. Navy Fuel Facility. Movement has continued since November 30, displacement on the water main now amounting to 2 feet. The area is a dip-slope in Cretaceous shales and sandstones; according to Moore (NEL Technical Report) the dips in this area are 5 to 10 degrees, which is less than the slope of the land surface just above the road. Up the hill from the cracking is the National Cemetery which has recently been expanded and where there is extensive watering of grass. This is an almost perfect example of dip-slope landsliding as has occurred recently in the Los Angeles area. Lt. Brown's suggestion that the slide was touched off by the November 30 shock is reasonable. However the basic cause is instability of the slope, and the effects of the watering in the cemetery should be investigated. It should be noted that movement occurred before any heavy rains had occurred. I would anticipate that the sliding will continue with the eventual result of carrying out the road and dumping several acres of Point Loma into the San Diego harbor channel entrance." USC&GS, MSA-100, 1958, p. 23.		

Case No. (See Figure G-5)	Location	Earthquake	Petroleum System Damaged
269	Highway 46, (1) mile east of Cholame, San Luis Obispo County within 35 miles of epicenter	Parkfield earthquake June 27, 1966 Intensity VII	Oil Pipeline
	"...broke a Union Oil Company pipeline along roadside." The Daily Press, June 29, 1966.		

APPENDIX H

CORROSION OF PETROLEUM SYSTEMS EQUIPMENT

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APPENDIX H

CORROSION OF PETROLEUM SYSTEMS EQUIPMENT

H.1 INTRODUCTORY SUMMARY

Corrosion is one of the most important factors to be considered in the design and operation of petroleum systems. The useful life of oil and gas field equipment is often significantly shortened as a result of corrosion. The cost of corrosion in petroleum systems equipment is high in the United States. In 1950, this cost was estimated by Uhlig to be $6 billion per year. This estimate was based on losses from corrosion, cost of maintenance, and cost of substituting more expensive corrosion-resistant materials for ordinary grades of iron or steel. Chilingar and Beeson (1969) estimated that the total cost of corrosion in the United States in 1965 was about $10 billion.

Corrosion of oil field equipment is not only costly but may lead directly or indirectly to oil spills. Volume I has pointed out a number of priority and routine points of spill vulnerability due to corrosion in Production and Gathering/Distribution (G/D) Systems. External corrosion of pipeline and gathering subsystems was found to be the most extensive cause of oil spillage from those systems. The Department of Transportation has promulgated in the Federal Register (Title 49 Part 195) extensive regulations covering corrosion control in main trunk liquid pipelines. Comparable requirements are not in effect for gathering subsystems and production facility flow lines.

The basic principles of corrosion and its mitigation are relatively straightforward. However, application of these principles to identify effective solutions to control corrosion problems for a specific facility is complex and generally requires the services of a corrosion engineer. Corrosion engineering is a specialized field requiring training and experience in electrochemistry and physical metallurgy. Individuals with professional qualifications in petroleum engineering, earth science, or water chemistry are not necessarily qualified as corrosion engineers. The National Association of Corrosion Engineers (NACE) recognizes individuals with professional qualifications in the corrosion engineering field.

This appendix supports the spill prevention guidelines of Volume I with a summary of corrosion fundamentals applicable to the spill vulnerability points for crude oil systems. Additional information can be obtained from the references given in Paragraph H.5. Detailed questions regarding corrosion control for a specific spill prevention problem should be referred to a corrosion engineer.

H.2 FUNDAMENTAL DEFINITIONS AND CORROSION MECHANISMS

H.2.1 Definitions

In general terms, corrosion (excluding mechanical erosion or abrasion) may be defined as the destructive attack of a metal by a chemical or electrochemical reaction with its environment. The basic driving force for this reaction is the tendency of produced or processed material, when placed in a natural environment, to return to its natural and more nearly stable chemical state.

Corrosion of oil field equipment results primarily from an electrochemical reaction. The reaction requires the following elements in order to proceed:

- Anode - A conductor which is electrically positive relative to the cathode
- Cathode - A conductor which is electrically negative relative to the anode
- Electrolyte - A conducting medium providing an electrical path between anode and cathode
- External Electrical Connection - An electrical path between the anode and cathode other than through the electrolyte.

When the circulation of electrical current of this reaction causes a discharge of electrons from the anode into the electrolyte, the anode may experience a depletion of material and formation of insoluble compounds. This depletion, or eating away, of anode material is corrosion. When it threatens the integrity of an oil field structure or vessel, a potential for oil spillage exists. Corrosion mitigation is accomplished if any of these basic reaction requirements are removed.

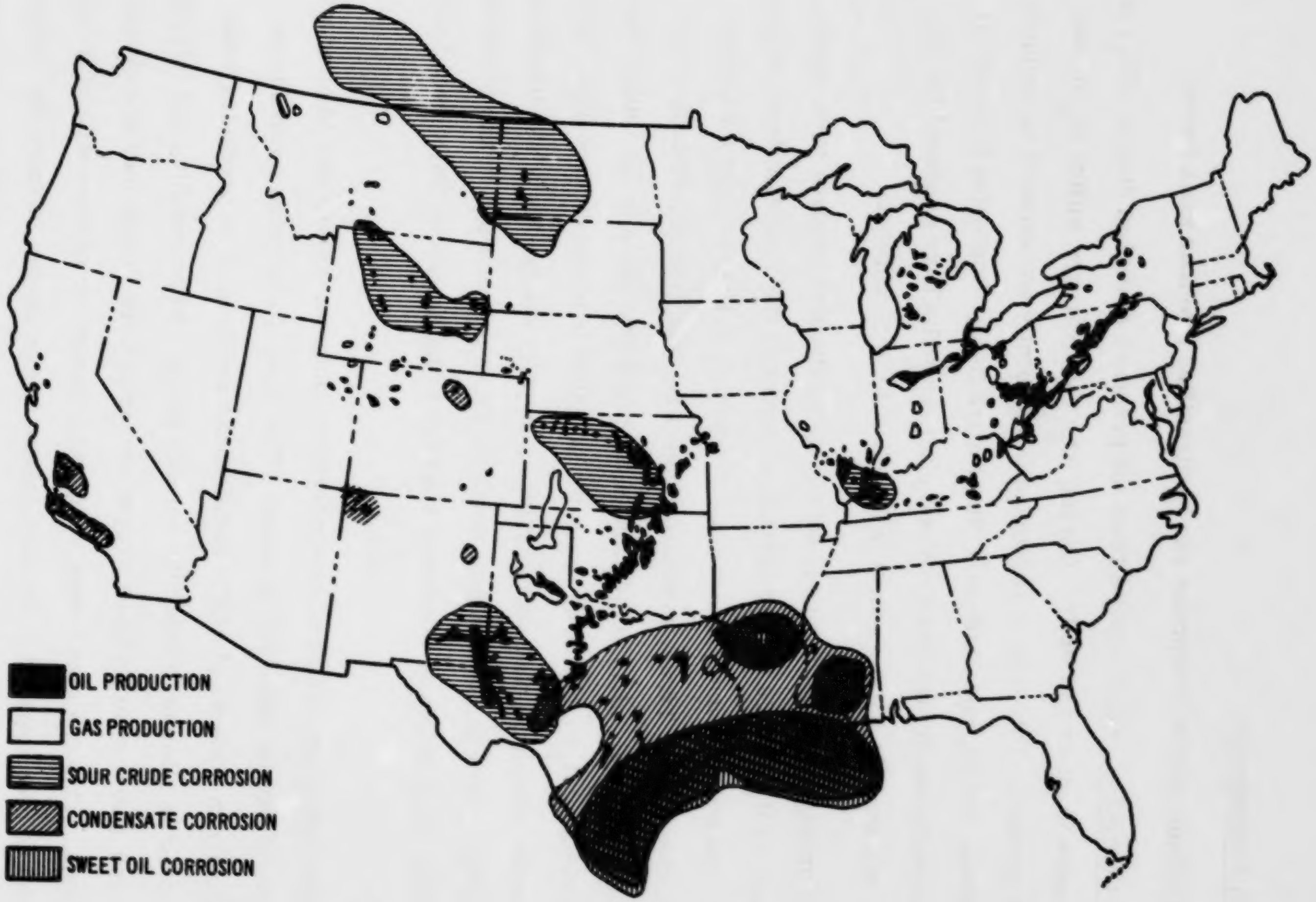
H.2.2 Corrosion Mechanisms

Corrosion in petroleum system equipment can be classified into four main types:

1. Sweet Corrosion, which results from the presence of carbon dioxide (CO_2) and fatty acids in oil or gas wells. Oxygen (O_2) and hydrogen sulfide (H_2S) need not be present. This type of corrosion is frequently encountered in southern Louisiana, Texas, and California (see Figure H-1). Corrosion in sweet oil or gas wells usually becomes serious after the wells have produced for several years and the salt water production reaches 40 to 50 percent.

2. Sour Corrosion, which occurs in oil and gas wells that produce even small amounts of H_2S. This type of corrosion occurs in the Permian Basin of West Texas and New Mexico, the Arbuckle production in Kansas, and Smackover production in East Texas, northern Louisiana, Mississippi, Alabama, and Florida. Approximately 40 percent of the producing wells in the United States are producing H_2S and thereby have the potential to become corrosive. Sulfide corrosion, which depends on moisture, generally starts slowly and increases with time, sometimes costing as much as $1100 per well per month to control (National Association of Corrosion Engineers and American Petroleum Institute, 1958).

3. Oxygen Corrosion, which occurs wherever equipment is exposed to atmospheric oxygen or oxygen dissolved in water. This type of corrosion occurs most frequently in offshore platform installations and in shallow producing wells where air is allowed to enter the annular space. Brine handling and injection systems also may experience oxygen corrosion even though they are closed systems. This can occur when component leakage or mixture with other water which has been exposed to the atmosphere allows oxygen to enter the system. The expansion of the offshore petroleum industry has resulted in high oxygen corrosion costs and presents a great challenge to corrosion engineers. In


OIL PRODUCTION
GAS PRODUCTION
SOUR CRUDE CORROSION
CONDENSATE CORROSION
SWEET OIL CORROSION

(Adapted from National Association of Corrosion Engineers, 1958)

Figure H-1. Corrosion Occurrence by Geographical Area

California's Santa Barbara Channel, exploratory wells have been drilled in 1200 feet of water. Offshore Louisiana operations have moved from 30- to 50-foot water depths into depths of 300 feet or more. Cook Inlet operations require design for 100-foot water depths and unusually severe corrosion conditions due to high tidal range, swift currents, and the resulting increased exposure to dissolved O_2 in the Inlet waters. Corrosion protection for offshore platforms, required for the "splash zone" and underwater surfaces as well as surfaces exposed to the atmosphere, can represent 10 percent of the platform total cost (Hanson and Hurst, 1969).

4. Galvanic and Electrochemical Corrosion, which results when electrical currents between anode and cathode exist, as in soil. Sea water is probably the most corrosive of all natural environments. Pipelines are necessarily placed in soil and sea water and therefore are subject to galvanic corrosion. There are a number of causes for these electrical currents. These include:
    a. Differing composition of materials between anode and cathode (bimetallic cell)
    b. Different temperatures between anode and cathode (temperature cell)
    c. Differences in homogeneity or concentration of the electrolyte (concentration cell)
    d. Stray currents (electrolytic cells) which flow or are induced from other structures and power sources.

H.3 MITIGATION

Mitigation techniques for electrolytic corrosion may be grouped into four general methods. They are:

1. Substitute a more corrosion resistant anode material for the item experiencing corrosion
2. Modify environmental parameters, including the corroding medium (or electrolyte), to reduce their active support of corrosion

3. Separate the equipment from its corrosive environment with a coating or other electrical barrier

4. Apply cathodic protection to establish a benign reaction in place of the undesired corroding reaction.

H.3.1 Substitution

A number of metallic and nonmetallic materials have been used in place of ordinary grade steels to provide corrosion protection of oil field equipment. These materials include plastic, aluminum, and special grade (stainless) steels. Plastic has been used for piping a number of fluids including gas. More recently, both plastic and aluminum pipe have been found suitable for some crude oil gathering applications within limited pipe size and line pressure. Stainless steel, and other corrosion resistant metals have been used for a variety of applications including drill pipe, sucker rods, valves and valve trim, fittings, and some piping and pressure vessels. Extensive use of stainless steel and comparable corrosion resistant metals can be expensive and invites tradeoff with other corrosion protection measures relative to the protection requirements.

Care must be exercised in the selection and use of different metals since it is possible to cause corrosion through bimetallic galvanic cells when dissimilar metals are in direct contact and exposed to the same electrolytic medium. By exception, if the amount (surface area) of anodic (corrodable) metal is large compared to the available surface area of the noble (cathodic and, thus, noncorrodable) metal, the rate of general corrosion of the anode will normally be low and may be tolerable in some applications. For example, a large steel (anodic) tank containing an electrically conductive fluid may experience negligible corrosion by having a copper (cathodic) fitting. By contrast, a steel (anodic) valve may experience severe corrosion when connected to a large copper (cathodic) vessel containing an electrically conductive fluid. The copper should not experience corrosion in either example.

H.3.2 Environmental Modification

In general, modification will be either through application of suitable construction techniques or the addition of a substance to the electrolyte. Construction could include support and drainage for a storage tank or underground pipeline. The electrolyte additives may be chemical treatments, corrosion inhibitors, or bactericides. The chemical treatments include use of oxygen scavengers, which reduce the amount of dissolved oxygen; dehydrators, which reduce the amount of water in the fluids (applicable to fluids with very low percent water); and alkaline substances which reduce the acidity of the fluids. Inhibitors and passivators may be either organic or inorganic substances. They function by forming a thin chemical film on the exposed metal parts which retards corrosion of the metal wall. Inorganic inhibitors include some soluble chromate and arsenic compounds. Organic inhibitors having different solubilities for oil and water may be selected, depending on the application. Bactericides usually provide effective elimination of certain bacteria which present corrosion problems. Some bacteria contribute to the formation of slime which can entrap dissolved oxygen at different concentrations at the metal surface and create a corrosion-producing galvanic cell. Other bacteria attack sulfate or sulfide compounds and produce H_2S.

All of these substances can be injected into producing wells, vessels, pipelines, down hole annular spaces, drilling mud, and casing cement, as required, and be effective against corrosion. Some of these substances are hazardous and require care in handling to assure safety of personnel, livestock, other safety requirements, and protection of the environment.

H.3.3 Separation

Separation normally takes the form of electrically isolating the anode, cathode, or electrolyte. Electrical isolation may result from use of insulated fittings and flanges. Applications include isolation of well casings, sections of coated pipe, tanks, production surface equipment, and pipelines. Coatings of nonconducting material or other protective substances may be grouped into the four broad categories of paint, metal coating, inorganic coatings, and organic coatings.

Paint provides protection of surface equipment from corrosion due to atmospheric oxygen. It is usually applied in several coats over a carefully prepared and cleaned metal surface, with a corrosion inhibiting primer coat. It is widely used for steel surface equipment and structures (including offshore platforms) and above-ground pipelines.

Metal coatings include galvanizing, cladding with noble metals like monel, and use of stainless steel sheets. One significant application of monel cladding or use of stainless steel sheets is for offshore platform supports in the tidal and splash zones. These supports would otherwise experience significant corrosion through intermittent exposure to atmospheric oxygen and aerated sea water. The relatively small surface area of cathodic monel or stainless steel (compared to that of the anodic total platform structure) allows negligible general corrosion of the platform from this bimetallic cell.

Inorganic coatings include oxide films, glass, and cement. Aluminum, although an active metal in the electromotive series, rapidly forms an oxide film that is self-healing and prevents further corrosion. Glass coatings are expensive, easily damaged and, thus, not frequently used. Applications would include internal tubing surfaces, and walls of pressure vessels. Portland cement is a very good coating since it is alkaline, tough, and dense. It is frequently used over pipe with an organic coating to provide additional protection and ballast for offshore pipelines and flowlines.

Organic coatings are the most frequently used for underground pipe. Major types include coal tar and asphalt enamels, plastic tapes, extrusion coatings, thin film fusion bonded coatings, and mastics.

H.3.4 Cathodic Protection

H.3.4.1 General

Cathodic protection is an electrical method for preventing corrosion. It is used on metallic structures which are in electrolytes such as soil or water. It has had widespread application on underground pipelines, and has been found to be effective on other underground and underwater structures such as storage tanks, steel pilings, well casings, and water treatment equipment. The method consists of installing electrodes into the soil or water (electrolyte) in contact with the equipment to be protected, and providing an external electrical connection (with or without electrical power) between the equipment and the newly installed electrodes. The intent is to stop the corrosion reaction, which used the equipment as the anode, by substituting a new and stronger reaction in which the installed electrodes are anodes (which may corrode without harming the equipment) and uses the equipment to be protected as a cathode which will not corrode. Cathodic protection operates by passing direct current continuously from electrodes, which are installed in the electrolyte, to the structure to be protected. Corrosion is arrested when the current is of sufficient magnitude and is properly distributed.

There are two basic methods of applying cathodic protection; the impressed current method and the sacrificial anode method. The impressed current method uses anodes which are energized by an external dc power source. In this type of cathodic protection system, anodes are installed in the electrolyte and connected to the positive terminal of the dc source. The structure which is to be protected is connected to the negative terminal of that source. Because the power source is almost always a rectifier unit, this type of system is often referred to as a rectifier type system. The sacrificial anode method of protection makes use of galvanic anodes, made from such materials as zinc or magnesium, which have a natural difference of potential with respect to the structure to be protected. These anodes are connected directly to the structure. In most cases, the rectifier type system is designed to deliver relatively large currents from a limited number of anodes. On the other hand, the sacrificial anode type system delivers relatively small currents from a large number of anodes.

Each method of applying cathodic protection has characteristics which make it more applicable to a particular problem than the other. A comparison of those characteristics is as follows:

Sacrificial Anode Method	Impressed Current Method
• Requires no external power	• External power required
• Fixed driving voltage	• Voltage can be varied
• Limited current	• Current can be varied
• Usually used where current requirements are small	• Can be designed for almost any current requirement
• Usually used in lower resistivity electrolytes	• Can be used in almost any resistivity environment

- In underground applications, interference with neighboring structures is usually negligible

- In underground application, interference with neighboring structures must be considered

Irrespective of the type of system used, current flows from the anode to the structure to be protected. When current flows onto a structure from the surrounding electrolytes, the potential is made more negative and cathodic protection is achieved when the change in potential is sufficient to arrest corrosion.

There are many differences in the design of cathodic protection systems. These differences result from the large variety of structures which are to be protected, and from the large variety of environments in which those structures are located. It is, therefore, necessary that each system be custom-designed for a given location. Rules-of-thumb should be avoided unless it can be shown that such rules are directly applicable to a particular design situation. In order to design a cathodic protection system properly, field measurements must be taken to determine the corrosion pattern and the current required for protection.

In order to prevent corrosion using cathodic protection, current must flow from the electrolyte onto the structure at all locations. If a portion of the structure does not receive current, the normal corrosion activity on that structure will continue. If any of the cathodic protection current picked up by the structure leaves that structure to flow back into the electrolyte, corrosion will be accelerated at the location where the current leaves. For example, an underground pipeline, in which mechanical joints are used, may be electrically discontinuous. If a galvanic anode type system is used for protection, it would be necessary to install an anode on each pipe length or to bond across each joint. If one length of pipe is neglected, that length will receive no cathodic protection and the normal corrosion activity will continue. When a rectifier type system is installed on a pipeline, it is even more important that the line be electrically continuous. If there are noncontinuous joints, it is possible for the cathodic protection current to leave the pipe and flow around that joint. Similarly, if cathodic protection current is applied to one structure in an area, it is possible for other structures in the neighborhood to be exposed to damage unless proper steps are taken. Measurements of potential are used to determine whether the possibility of such exposure to damage exists. Just as protection is indicated when the potential of a structure is made more negative, exposure is indicated when the potential of a structure is made less negative as the result of the application of current.

New, cross-country pipelines are provided with a good, high resistivity coating applied with techniques which leave little of the pipe surface exposed to the soil. However, a coating, no matter how good or how well applied, is rarely if ever perfect, and protection afforded by the coating must be supplemented with cathodic protection to achieve complete protection against corrosion. It has been noted that coated pipelines can develop leaks within a shorter period of time than uncoated pipelines. This is true even though the total metal loss on a coated pipe is appreciably less than on a bare pipe. Coating and cathodic protection work well together. When a pipe is coated with the materials and techniques currently available, a relatively small magnitude of current can provide cathodic protection for many miles of pipe.

The problems presented in attempting to provide cathodic protection for bare pipelines are more difficult than those on coated pipelines. A major difficulty is the need for a much greater magnitude of current.

Because of the large currents required to provide complete protection for a length of bare pipe, a technique known as "hot spot" protection is used. In this type of system, a detailed survey of the pipeline is made during which potential measurements and soil resistivity measurements are taken at very close intervals, sometimes as close as 10 feet apart but more often from 50 to 100 feet apart. Evaluation of these measurements is made, the more corrosive areas are selected, and anodes are installed at those corrosive areas or "hot spots." Generally, "hot spot" protection also requires a large number of anodes.

H.3.4.2 Application to Design of Offshore Platforms

Good corrosion control for offshore production platforms begins with structural design, and it is necessary to select the best possible structure-environment combination. Basically, this involves the consideration of the following two groups of factors:

1. Factors Associated with the System Materials
   - Effective electrolyte potential of the metal
   - Overvoltage of hydrogen on the metal
   - Tendency of metal to form an insoluble protective film
   - Chemical and physical homogeneity of the metal surface.
2. Factors Associated with the Environment
   - Oxygen concentration
   - Acidity of solution
   - Natural concentration and distribution of electrolytes
   - Tendency of environment to deposit a protective film on metal surface
   - Rate of flow of solution against metal
   - Temperature
   - Static or cyclic stresses
   - Contact with dissimilar solutions
   - Contact between dissimilar metals.

Simple, continuous shapes should be used throughout the structural system. If possible, all edges, holes, crevices, and internal corners which may be inaccessible to anti-corrosion maintenance should be eliminated.

Marine environments are hostile. Three separate zones exist for which corrosion control must be planned, (Hanson and Hurst, 1969). See Figure H-2. Approximate corrosion rates in the Gulf of Mexico for these three zones are:

- Atmospheric zone - 5 to 10 mils (0.001-inch penetration = 1 mil) per year
- Splash zone - up to 55 mils per year
- Immersed zone - up to 25 mils per year.

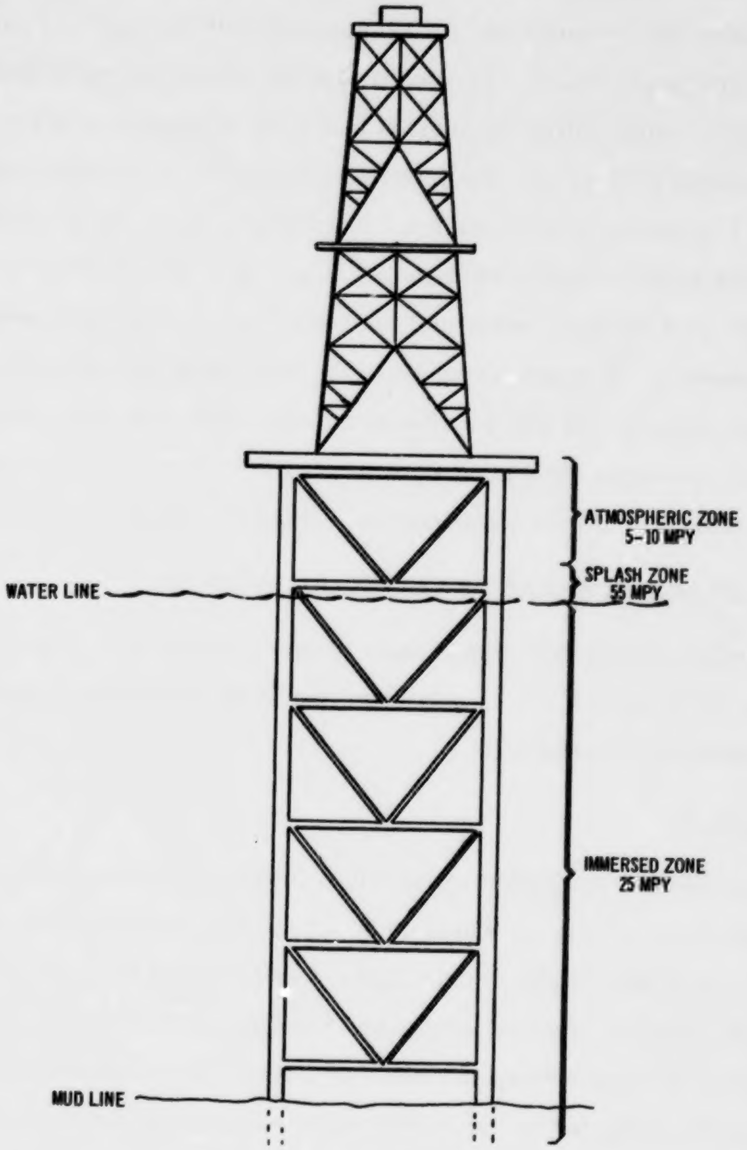

ATMOSPHERIC ZONE
5-10 MPY
SPLASH ZONE
55 MPY
WATER LINE
IMMERSED ZONE
25 MPY
MUD LINE

Figure H-2. Structural Corrosion Zones

Table H-1 lists a number of factors which must be considered in implementing corrosion protection design for offshore petroleum systems.

Atmospheric zones are normally protected by paint. The splash zone experiences the most severe corrosion environment since it is intermittently exposed to atmospheric oxygen and submerged in sea water. Erosion limits the effectiveness of many coatings including paint; and the intermittent immersion in the electrolytic sea water limits the effectiveness of cathodic protection. Protective measures have included use of monel cladding and the use of stainless steel sheets. In addition, sizing of the platform supports for structural design safety margins reduces the chance that the effects of corrosion would be significant over the expected useful platform life. Immersed zones are usually under cathodic protection. In many instances in the Gulf Coast and off California, cathodic protection systems may use sacrificial anodes made from aluminum or magnesium alloys. In other instances, including Cook Inlet, the severity of the corrosion environment requires the use of impressed current cathodic protection systems.

H.4 CORROSION PROBLEM AREAS OF CRUDE OIL SYSTEMS

Problems are considered from two standpoints: those documented in the literature reviewed during the study but not necessarily resulting in oil spills; and those exhibited by the spill data discussed in Appendix E.

H.4.1 Drilling Systems

In general, Drilling System equipment experiences fewer corrosion problems than Production or G/D Systems. Problems which do occur include external corrosion of casing, and combined corrosion and fatigue of drill pipe. Casing corrosion may be mitigated by cathodic protection, paint or other coatings, and through use of electrical insulation. However, cathodic protection of deep casings may present considerable difficulty. Drill pipe corrosion may be mitigated by use of internal coatings, corrosion resistant steels, and chemical inhibitors. In addition, corrosion inhibitors may be introduced into annular spaces, casing setting cement, and the mud subsystem. When sour gas or sour crude is anticipated, additional precautions may include use of an oil base mud (to minimize water contact with H_2S) and trimming of the BOP stack for sour gas service. With the exception

Table H-1. Sample Environmental Data Needed for Corrosion Protection Design

1. What are average, minimum, and maximum tidal fluctuations at site (feet)?
2. What are average, minimum, and maximum tidal currents at site (knots)?
3. What are average, minimum, and maximum water temperatures at surface (°F)?
4. Sea conditions:

   Calm__________% total time per year
   Low__________% total time per year
   High__________% total time per year

5. Swell condition:

   No swells__________% total time per year
   Low__________% total time per year
   High__________% total time per year

6. Maximum swells anticipated____________________ft.
7. Maximum waves (storm) anticipated______________ft.
8. Any unusual reoccurring storm conditions? Describe.
9. Water depth at site_______________ft.
10. Pile penetration below mud line:

    Average_____________ ft.
    Maximum_____________ ft.
    Minimum_____________ ft.

11. Salinity (g./kg.)

    Average_____________
    Maximum_____________
    Minimum_____________

12. Water resistivity (ohm-cm.):

    Average_____________ . _______% per year
    Maximum_____________ . _______% per year
    Minimum_____________ . _______% per year

13. Do drawings of structure show all underwater steel surfaces (grout lines, reach rods, conductor pipes, etc.)? If not, give details.
14. Are gathering, flare, or transmission pipe lines connected to structure or in close proximity? Give details. Are pipe lines coated and/or cathodically protected? If so, give details.

Table H-1. Sample Environmental Data Needed for Corrosion Protection Design (Continued)

15. Is structure (below water line) to be painted? If so, give material and application specification.

16. Are any special corrosion-resistant or high-strength alloys to be employed on the submerged or tidal zone of the structure? If so, give details.

17. Will permanent, continuous ac power be available on structure? If so, advise:

______________ volts, ______________phase,
______________ cycle, ______________KVA available

18. Will cathodic protection electrical equipment be located in hazardous area (requiring explosion-proof system)?

19. Can electrical equipment be located within ventilated (or air conditioned) room (permitting air cooled equipment)?

20. What is the required life of the structure? ________________ years

21. Is it anticipated that any marine vessels will be moored at the structure for prolonged periods of time? If so, give details.

22. Will there be any operating equipment on the structure which might cause continuous and extensive vibration?

23. Will there be any dc electrical equipment (other than cathodic protection) on the structure?

24. Is any future extensive welding anticipated?

25. Is there any sewerage or industrial waste effluent discharged near or flowing to the vicinity of the structure?

26. What is the water pH at the structure site?

Average ______________
Maximum______________
Minimum______________

27. Are there any unusual wastes to be discharged overboard at the structure?

28. Is the structure to be located where fresh water intrusion is continuously or periodically encountered (run-off, river discharge, etc.)?

29. Is heavy floating debris or ice anticipated? If so, give details.

30. In the general area of the structure is there any history of extensive submarine organism growth? Plants, animal?

of permanently installed down hole components, most drilling equipment is subject to visual inspection for corrosion damage during tripping and in the period following rig-down and prior to rig-up for the next drilling operation. The spill data for Drilling Systems did not identify any corrosion problems contributing to crude oil spills or blow-outs.

H.4.2 Production Systems

Corrosion problems in Production Systems have been extensively documented in the technical literature. Down hole equipment is exposed to produced brine water and frequently to either sour (H_2S) or sweet (CO_2) agents capable of producing both generally and locally severe corrosion. Any dissolved O_2 in the water also will greatly increase corrosion. Normally, produced brine contains little or no O_2 unless it is exposed to the atmosphere at the Earth's surface or mixed with other similarly exposed water.

External corrosion of surface equipment occurs as a result of atmospheric O_2. Internal corrosion of separators and storage tanks also is experienced. Tank bottoms are subject to external corrosion by soil action. In any of these equipment (especially those with low fluid velocity) the accumulation of sludge, scale, or sediment in the lower regions of the vessel frequently localizes and accelerates corrosion.

Water disposal subsystems frequently experience corrosion and present many difficulties in mitigation. However, the study data indicated few oil spills resulting from corrosion of these subsystems.

Custody transfer subsystems have occasionally exhibited corrosion attributed to use of dissimilar metals in LACT unit installations. However, the spill data did not show this to be a problem.

Pipe leaks in gathering subsystem flowline equipment is the largest single source of oil spillage from Production Systems. For onshore applications, the predominant cause of leaking is attributed to corrosion (70 percent external, 30 percent internal). External corrosion of buried pipe may be controlled, in most cases, by the combined application of coating and cathodic protection. Since cathodic protection is considerably more costly for uncoated pipe, a surface survey of the bare pipeline can be made to determine areas where active corrosion is in progress. Cathodic protection may then be limited to those areas to reduce overall cost. If cathodic protection is not used, but coating is applied, corrosion may occur at holidays (voids or weaknesses) in the coating. Uncoated lines in the section can be partially protected by use of insulated flanges and fittings. Other mitigation methods include the use of aluminum pipe and the use of plastic pipe of limited diameters and pressures. Internal corrosion mitigation may be accomplished with internal coatings, chemical inhibitors, and chemical treatment to reduce acidity and oxygen content.

Oil spills have been attributed to leaking of onshore tank shells and bottoms. In many instances the quantity of spill was substantial and secondary containment was inadequate (see Appendix E). External shell corrosion may be controlled by painting if the metallic surface can be cleaned and a corrosion resistant primer coating is used. Internal shell corrosion may be controlled by paint or other selected coatings, including metal coatings, inhibitors, or other chemical treatment to control acidity or water in the stored fluids. In addition, cathodic protection may be possible by suspending the system's anodes inside the tank shell given that the stored liquids are sufficiently electrolytic to support current flow.

Tank bottom internal corrosion may be mitigated by coating, treatment of the stored liquids as previously mentioned, and cleaning to remove sludge and sediment capable of entrapping corrosive agents at local points on the bottom.

Tank bottom external corrosion may be controlled by coating, cathodic protection, and a foundation designed for maximum drainage of ground water away from the tank. If the tank bottom is coated, cathodic protection should also be used to prevent locally severe corrosion at points where there are holidays in the coating. Otherwise, the corrosion current, which generally would corrode the entire unprotected bottom at a slow rate, may concentrate at any breaks in the coating and cause perforation at a much higher rate than if the bottom were not coated. A good coating, however, greatly reduces the current requirements for a complementary cathodic protection system.

Oil spills in safety subsystems have been attributed to high liquid level sensor failures in offshore storage tanks and sump systems, and in onshore storage tanks, separators, and treaters. In general, mitigation measures for tank shell internal corrosion should be applicable to protect the level sensors, which are mounted internally and exposed to the vessel liquids and the atmosphere. In addition, sensors selected for these applications should be designed for corrosion service.

Fire tubes in onshore heater treaters in treater subsystems have been responsible for some reported leaks and, thereby, oil spills. Normally, these tubes are internally fired and placed in the vessel so that the external surface is in direct contact with and exchanges heat energy to the produced liquids. As a result, the fire tubes experience a severe corrosion environment on both internal and external surfaces. No corrosion mitigation measures have been identified as applicable to fire tubes. Since they are relatively inexpensive and removable, frequent inspection and replacement, as required, may be a practical approach to prevent oil spillage. Inspection frequency could be based on corrosivity, throughput and pressure of produced fluids or of the fuel used, proximity of the facility to waterways or other local factors, and whether the facility is continuously manned, and has adequate provisions for safety shut-in and secondary containment.

H.4.3. Gathering/Distribution Systems

Corrosion problems in G/D Systems have received extensive attention. Crude oil pipelines and gathering lines (with BS&W held to 1 percent) experience internal and external corrosion due to O_2 and H_2S. Buried pipelines also experience external galvanic corrosion in the soil environment. Mitigation measures include coatings, cathodic protection, and electrical insulation for external corrosion; and inhibitors, chemical treatment, and coating for internal corrosion.

Mitigation methods for storage subsystem corrosion are similar to those identified for Production System local storage subsystems and the additional use of dehydration to remove water from the stored fluids. No corrosion problems of significance were identified for pump stations.

Pipeline and gathering subsystem pipe corrosion was, by a wide margin, the largest single cause of oil spillage, with an indicated distribution of 80 percent external and 20 percent internal corrosion. Mitigation methods previously described for Production System gathering subsystems are applicable except that the possibility of using plastic pipe should be limited to gravity type gathering subsystems, or other low pressure gathering functions with small diameter pipe. In addition, dehydration of transported fluids may be considered.

Road crossing pipe, since they may be at a low point in the line section, and encased to limit mechanical damage, present possible corrosion problems in addition to those of pipelines in general. From the standpoint of gathering subsystem road crossing internal corrosion, pipe radii and bends could be made sufficiently gradual to accommodate internal passage of scrapers or spheres (also called pigs or go-devils) for pipe internal maintenance including removal of entrapped water. (This is already a DOT requirement for main trunk liquid pipelines.) From the standpoint of external corrosion, the use of metallic external casings to protect the line passing under a roadway presents a problem. If the line has electrical contact with the casing and any material in the annular space is electrolytic, an active corrosion cell will result. Subject to State and local regulation, consideration could be given to a road crossing which would not require an external casing to provide mechanical protection under the road. If a protective casing is used, corrosion mitigation methods could include measures to ensure electric insulation of the casing from the pipe. An additional measure would be to fill the annular space with an electrically resistant and corrosion resistant material which could permanently displace any moisture.

H.5 REFERENCES

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APPENDIX I

REGULATION REVIEWS SUMMARY REPORTS

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APPENDIX I

REGULATION REVIEWS SUMMARY REPORTS

I.1 INTRODUCTION SUMMARY

The spill prevention program described in this report is intended to respond to existing Federal legislation and proposed regulations. The regulations, statutes, and related documents were gathered, reviewed, and summarized to identify the total program interfaces with the oil spill prevention program. The reports most pertinent to the provisions of Volume I are included in this appendix and consist of the following:

- Federal Water Pollution Control Act of 1972
- Title 3 - The President, Executive Order 11548, Delegating Functions of the President Under the Federal Water Pollution Control Act, as Amended, July 20, 1970
- Reorganization Plan No. 3 of 1970
- Memorandum of Understanding between the Environmental Protection Agency and the Department of Transportation concerning the Definition of Transportation-related and nontransportation-related facilities as used in Executive Order 11548, December 18, 1971
- National Oil and Hazardous Substances Pollution Contingency Plan
- Code of Federal Regulations, Title 33, Part 153 - Control of Pollution by Oil and Hazardous Substances, Discharge Removal.

A number of State and Federal regulations, including the Refuse Act, also have been reviewed to determine requirements and practices. These were not summarized since they either were not pertinent or had been summarized in a prior EPA report.

This appendix is included to provide a quick summary of regulatory provisions of significance to the spill prevention plan.

I.2 REGULATION REVIEWS SUMMARY REPORTS

In preparing summary reports of documents that were found applicable, consideration had to be given to their content. The contents of the summaries are limited to discussion of only those sections directly applicable to this program. The pertinent items considered to be of interest are reflected in Figure I-1. The remainder of this appendix provides the Regulation Review Summary Reports for the regulations identified in Paragraph F.1.

1. TITLE - Title of the document reviewed
2. AGENCY - Name of the agency which issued the document
3. DATE - Effective Date
4. APPLICABILITY - A statement of the areas, items, or actions of interest to which the document applies.
5. ADMINISTRATION AND ENFORCEMENT PROVISIONS - A statement which describes the individual, office, or agency responsible for the administration and enforcement of the provisions of the document. Also, a statement of the penalties imposed for violation of the document's provisions.
6. HARDWARE REQUIREMENTS - A brief statement describing the system, equipment, and/or component hardware requirements imposed by the document.
7. PROCEDURE REQUIREMENTS - A statement describing any procedural requirements imposed by the document as they pertain to inspection, operation, or maintenance.
8. DATA REPORTING REQUIREMENTS - A statement describing the requirement for reporting and/or maintaining records of configurations, production, maintenance, inspection, or failures (spills).
9. GENERAL COMMENTS - Any relevant comments not covered by the above.

Figure I-1. Regulation Review Summary Report Format

REGULATION REVIEW - SUMMARY REPORT

1. TITLE - Federal Water Pollution Control Act

2. AGENCY - Environmental Protection Agency

3. DATE - October 18, 1972

4. APPLICABILITY - This Act applies to all United States' water resources. However, Section 311 deals with control of pollution by oil and other hazardous substances.

5. ADMINISTRATION AND ENFORCEMENT PROVISIONS - The Secretary of Interior originally was responsible for administration of this Act. However, Section 311 of this Act assigns most responsibility in the area of oil pollution to the President. Subsection (b) (3) requires the President to issue regulations which define the quantities of discharged oil which constitute a violation of this Act. Subsection (c) authorizes the President to act to remove discharged oil from the environment and directs that he prepare and publish a National Contingency Plan for removal of oil. Items to be included in the Plan are described. Subsection (j) requires the President to issue regulations regarding various aspects of oil pollution cleanup and prevention while Subsection (l) authorizes the President to delegate the administration to appropriate Federal activities.

   Various subsections of Section 311 prescribe legal remedies and penalties for oil pollution. Those violations and penalties of interest to this study are:

VIOLATION	PENALTY
Failure to report oil discharges	$10,000 fine and/or not more than 1 year imprisonment
Discharge of oil	Civil penalty of not more than $5,000 for each offense
Oil discharge from onshore or offshore facilities	Removal costs not to exceed $8,000,000 except in the case of willful negligence or willful misconduct which results in a liability for the full cost
Failure or refusal to comply with regulations	Civil penalty of not more than $5,000 for each violation

6. HARDWARE REQUIREMENTS - Section 311 (j) (l) (C) authorizes issuance of regulations establishing requirements for equipment to prevent discharges of oil and hazardous substances from vessels and onshore and offshore facilities.

7. PROCEDURE REQUIREMENTS - Section 311 (j) (l) (C) authorizes issuance of regulations establishing procedures and methods to prevent discharges of oil and hazardous substances from vessels and onshore and offshore facilities.

8. NOTIFICATION REQUIREMENTS - Section 311 (b) (5) requires any person in charge of a vessel or of an onshore or an offshore facility to notify the appropriate United States Government agency as soon as he has knowledge of discharge of oil or hazardous substances.

9. GENERAL COMMENTS - This Act provides the basis for prevention and cleanup of oil pollution through establishment of National, Regional, and Local Contingency Plans and Regulations.

REGULATION REVIEW - SUMMARY REPORT

1. TITLE - Title 3 - The President, Executive Order 11548 Delegating Functions of the President Under the Federal Water Pollution Control Act, as Amended.

2. AGENCY - The President - Richard M. Nixon

3. DATE - July 20, 1970

4. APPLICABILITY - Same as Federal Water Pollution Control Act.

5. ADMINISTRATION AND ENFORCEMENT PROVISIONS - This Order delegates functions of the President under the Federal Water Pollution Control Act to others as follows:

Secretary of the Interior (and subsequently to the Administrator of the Environmental Protection Agency by Reorganization Plan No. 3 of 1970).

- To carry out the provisions of Section 311, Subsection (b) (4) relating to the determination of those quantities of oil the discharge of which, at such times, locations, circumstances, and conditions, will be harmful. . . .
- To carry out the provisions of Section 311, Subsection (e) to secure relief through court action to abate actual or threatened discharges of harmful quantities of oil.
- To carry out the provisions of Section 311, Subsection (j) (1) (C) to establish procedures, methods, and requirements for equipment to prevent discharges of oil from nontransportation-related onshore and offshore facilities.

Council on Environmental Quality

- To carry out the provisions of Section 311, Subsection (c) (2) providing for the preparation, publication, revision, or amendment of a National Contingency Plan for the removal of oil.

Secretary of the Interior (Administrator of EPA) and Secretary of Transportation

- Responsibility and authority to implement Section 306.2 of the National Contingency Plan as follows: EPA shall furnish or provide the On Scene Coordinators (OSCs) for inland navigable waters and their tributaries. USCG shall furnish or provide for OSCs for the high seas, coastal, and contiguous zone waters, and for Great Lakes coastal waters, ports, and harbors.
- To carry out the provisions of Section 311, Subsection (d) for coordination and direction or removal or elimination of the threat of oil or hazardous substance discharges.

Commandant of the Coast Guard

- Shall issue regulations implementing his designation as the "appropriate agency" for the purpose of receiving the notice of discharge of oil required by Section 311, Subsection (b) (5).

6. HARDWARE REQUIREMENTS - Not applicable.

7. PROCEDURE REQUIREMENTS - Authority to issue regulations required to implement the assigned administrative responsibilities is granted by Section 8 of the Executive Order.

8. DATA REPORTING REQUIREMENTS - The Coast Guard is authorized to establish any Data Reporting Requirements necessary.

9. GENERAL COMMENTS - This Executive Order delegates Presidential responsibilities and authorities authorized under the Federal Water Pollution Control Act. It also refers to the Reorganization Plan No. 3 of 1970 and the National Contingency Plan.

REGULATION REVIEW - SUMMARY REPORT

1. TITLE - Reorganization Plan No. 3 of 1970

2. AGENCY - The President

3. DATE - July 9, 1970

4. APPLICABILITY - Same as the Federal Water Pollution Control Act

5. ADMINISTRATION AND ENFORCEMENT PROVISIONS - Not Applicable

6. HARDWARE REQUIREMENTS - Not Applicable

7. PROCEDURE REQUIREMENTS - Not Applicable

8. DATA REPORTING REQUIREMENTS - Not Applicable

9. GENERAL COMMENTS - This plan established the Environmental Protection Agency and transferred to the Administrator of EPA all functions vested by law in the Secretary of the Interior and the Department of Interior but in fact administered by the Federal Water Quality Administration. All previous functions assumed by the Secretary of the Interior in Reorganization Plan No. 2 of 1966 (80 Stat. 1608), and all functions vested in the Secretary of the Interior or the Department of the Interior by the Federal Water Pollution Control Act or by provisions of Law Amendatory or supplementary thereof were also transferred.

REGULATION REVIEW - SUMMARY REPORT

1. TITLE - Memorandum of Understanding Between the Environmental Protection Agency and the Department of Transportation Concerning the Definition of Transportation Related and Nontransportation Related Facilities as Used in Executive Order 11548.

2. AGENCY - Department of Transportation and Environmental Protection Agency.

3. DATE - December 18, 1971.

4. APPLICABILITY - Same as Federal Water Pollution Control Act.

5. ADMINISTRATION AND ENFORCEMENT PROVISIONS - This memorandum defines the respective areas of responsibility for the Environmental Protection Agency and the Department of Transportation as distinguished by the terms Nontransportation-Related and Transportation-Related as used in Executive Order No. 11548. It was noted that the DOT responsibilities were redelegated to the Coast Guard.

6. HARDWARE REQUIREMENTS - Not applicable.

7. PROCEDURE REQUIREMENTS - Not applicable.

8. DATA REPORTING REQUIREMENTS - Not applicable.

9. GENERAL COMMENTS - This memorandum of agreement was prepared to more clearly define the responsibilities and authorities of the two agencies.

REGULATION REVIEW - SUMMARY REPORT

1. TITLE - National Oil and Hazardous Substances Pollution Contingency Plan.
2. AGENCY - Council on Environmental Quality.
3. DATE - 1973 (Not published at time of this report.)
4. APPLICABILITY - This Plan is effective for all United States navigable waters, their tributaries, and adjoining shorelines. This includes inland rivers, Great Lakes, coastal territorial waters, the contiguous zone, and high seas where there exists a threat to United States waters, shoreface, or shelf-bottom.
5. ADMINISTRATION AND ENFORCEMENT PROVISIONS - This Plan describes the administrative structure for responses to actual or potential pollution discharges and defines responsibilities and authorities. The administrative elements of particular interest to this study are as follows:
   - The Council on Environmental Quality is responsible for the preparation, publication, revision, and amendment of the National Contingency Plan, receiving its advice from the National Response Team.
   - The Environmental Protection Agency (EPA) chairs the National Response Team. EPA also chairs the Regional Response Teams and provides the On Scene Coordinator (OSC) for inland navigable waters and their tributaries.
   - The United States Coast Guard provides the vice-chairman for the National Response Team. The United States Coast Guard also chairs the Regional Response Teams and provides OSC for high-seas, coastal, and contiguous zone waters, and for Great Lakes, coastal waters, ports, and harbors. In addition, the USCG provides the headquarters site for the National Response Center (NRC).

The remaining organizational structure is described in Figure 1-2. Regional Contingency Plans are maintained at the local District or Regional offices of the USCG and EPA, as appropriate.

6. HARDWARE REQUIREMENTS - Not applicable.

7. PROCEDURE REQUIREMENTS - Not applicable.

8. DATA REPORTING REQUIREMENTS - The item of primary interest to this program, which is contained in the National Contingency Plan, is the spill data reporting requirements. The reporting requirements of this plan are not definitive nor is there a form or format requirement. Details are left to the discretion of the Regional or other lower tier plans. The reporting requirements are partially described in various parts of the Plan. Figure 1-3 illustrates the reporting flow which is briefly described in the following paragraphs.

Discovery and notification of spills is subdivided into three categories: report by discharger, deliberate discovery, and random discovery. In the case of notification by discharger, the discharger is required to report to designated Federal Agencies listed in Title 33, Part 153, Subpart B, Code of Federal Regulations, promulgated by the Coast Guard. In the event of deliberate discovery, the spill is reported directly to the Regional Response Center (RRC). Random discoveries are reported to the nearest Coast Guard or EPA Office. The initial report should be in accordance with the information and format as described in the Regional Plans. The severity of the spill will determine the reporting procedure. Regional Plans should specify the reporting procedures for various areas and, based upon severity as determined by the nature and quantity of material spilled, the location and resources adjacent to the area. In general, all spills should be reported to the OSC and the RRC; medium spills are reported by teletype to the RRC and NRC; while major or potential major spills are reported to the RRC and NRC by telephone and teletype.

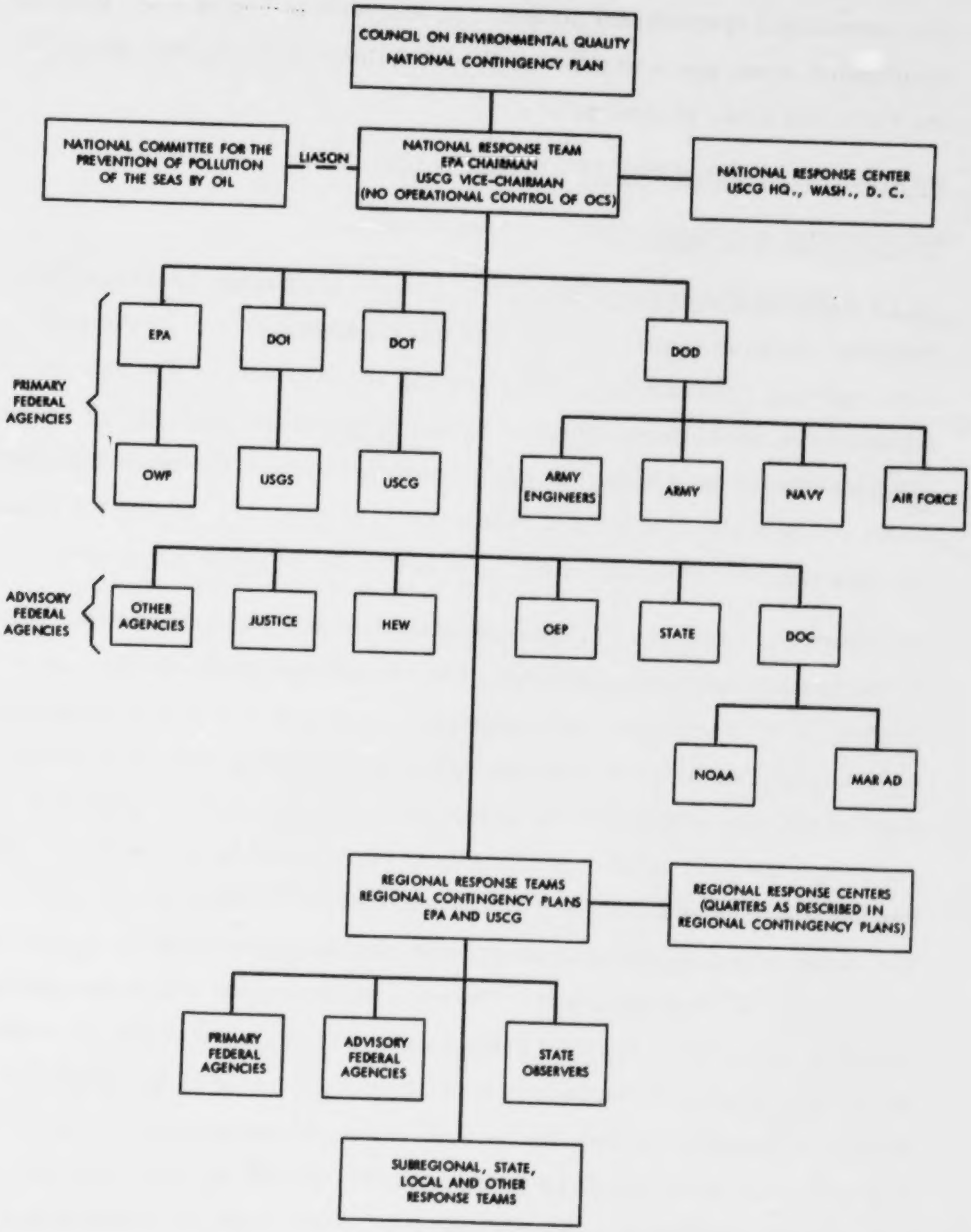
COUNCIL ON ENVIRONMENTAL QUALITY
NATIONAL CONTINGENCY PLAN
NATIONAL COMMITTEE FOR THE PREVENTION OF POLLUTION OF THE SEAS BY OIL
LIASON
NATIONAL RESPONSE TEAM
EPA CHAIRMAN
USCG VICE-CHAIRMAN
(NO OPERATIONAL CONTROL OF OCS)
NATIONAL RESPONSE CENTER
USCG HQ., WASH., D. C.
PRIMARY FEDERAL AGENCIES
EPA
DOI
DOT
DOD
OWP
USGS
USCG
ARMY ENGINEERS
ARMY
NAVY
AIR FORCE
ADVISORY FEDERAL AGENCIES
OTHER AGENCIES
JUSTICE
HEW
OEP
STATE
DOC
NOAA
MAR AD
REGIONAL RESPONSE TEAMS
REGIONAL CONTINGENCY PLANS
EPA AND USCG
REGIONAL RESPONSE CENTERS
(QUARTERS AS DESCRIBED IN REGIONAL CONTINGENCY PLANS)
PRIMARY FEDERAL AGENCIES
ADVISORY FEDERAL AGENCIES
STATE OBSERVERS
SUBREGIONAL, STATE, LOCAL AND OTHER RESPONSE TEAMS

Figure I-2. Organizational Structure for the National Oil and Hazardous Substances Pollution Contingency Plan

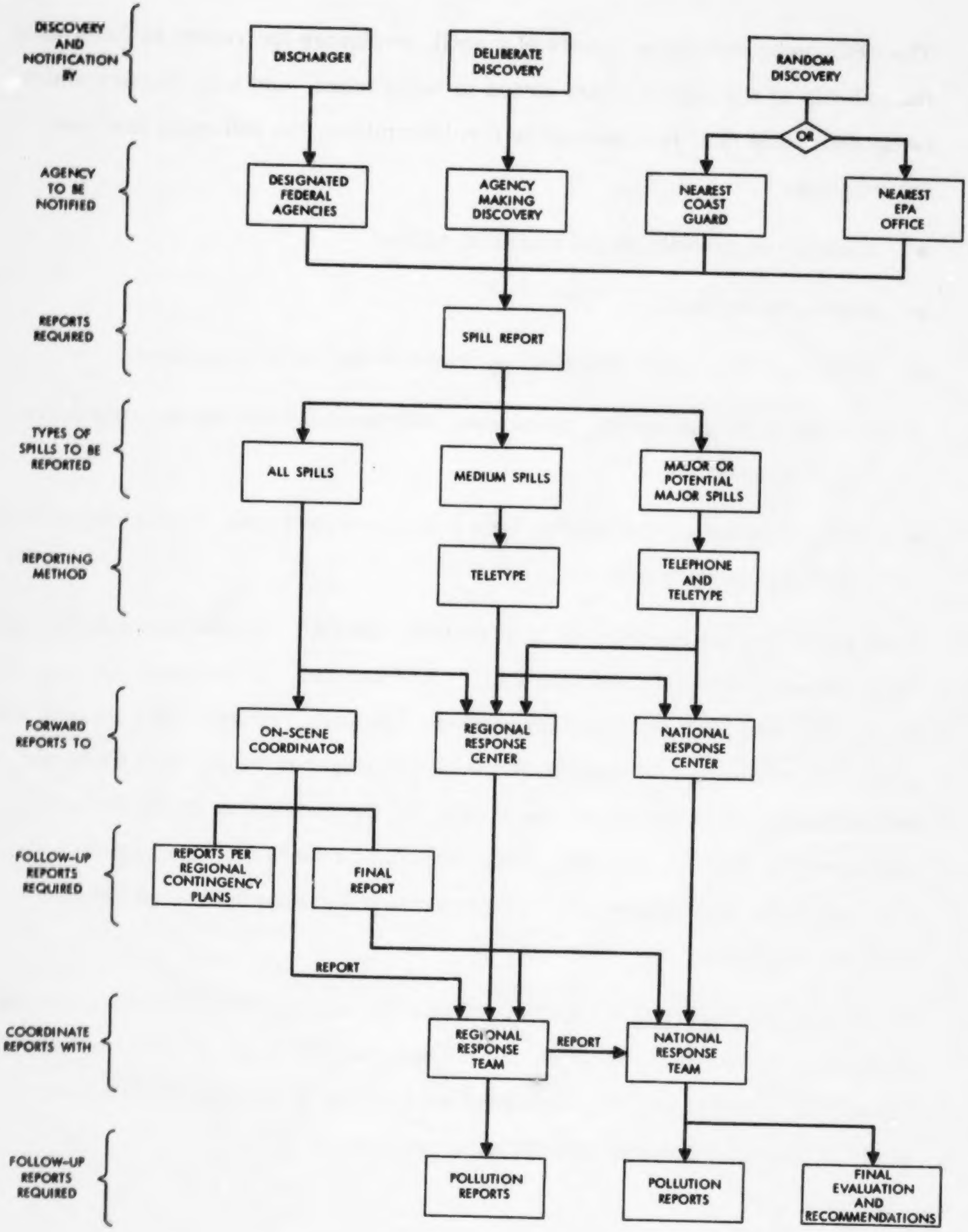
DISCOVERY AND NOTIFICATION BY
DISCHARGER
DELIBERATE DISCOVERY
RANDOM DISCOVERY
OR
AGENCY TO BE NOTIFIED
DESIGNATED FEDERAL AGENCIES
AGENCY MAKING DISCOVERY
NEAREST COAST GUARD
NEAREST EPA OFFICE
REPORTS REQUIRED
SPILL REPORT
TYPES OF SPILLS TO BE REPORTED
ALL SPILLS
MEDIUM SPILLS
MAJOR OR POTENTIAL MAJOR SPILLS
REPORTING METHOD
TELETYPE
TELEPHONE AND TELETYPE
FORWARD REPORTS TO
ON-SCENE COORDINATOR
REGIONAL RESPONSE CENTER
NATIONAL RESPONSE CENTER
FOLLOW-UP REPORTS REQUIRED
REPORTS PER REGIONAL CONTINGENCY PLANS
FINAL REPORT
REPORT
COORDINATE REPORTS WITH
REGIONAL RESPONSE TEAM
REPORT
NATIONAL RESPONSE TEAM
FOLLOW-UP REPORTS REQUIRED
POLLUTION REPORTS
POLLUTION REPORTS
FINAL EVALUATION AND RECOMMENDATIONS

Figure I-3. Spill Reporting

The OSC, upon receipt of report of a spill, evaluates the report to determine the validity of the report, what action is being taken, and what further action is needed. The OSC is responsible for determining the following pertinent information:

- Nature and quantity of the material spilled
- Source of the spill
- Location, direction, and time of travel of the spilled material
- Threat to human health, resources, and installations and the priorities for protecting them
- Person reporting the spill is taking appropriate action in accordance with FWPCA, as amended.

Upon gathering the appropriate information, the OSC reports to the discharger, State and local officials, and the RRC. As indicated, he recommends activation of the RRT and NRT and provides periodic situation reports. His reports are prepared in accordance with the Regional Contingency Plan. The RRTs and NRT submit pollution reports twice each day. At the conclusion of the Federal participation activity, the OSC prepares a final report for submission to the RRT and NRT, whereupon the NRT prepares a final evaluation and makes recommendations.

9. GENERAL COMMENTS - This document is primarily devoted to organizational structure, authorities, and responsibilities for responses to spills of oil and hazardous substances. The essential application of this source document to this study is the establishment of reporting requirements.

REGULATION REVIEW - SUMMARY REPORT

1. TITLE - Code of Federal Regulations Title 33, Part 153 - Control of Pollution by Oil and Hazardous Substances, Discharge Removal.

2. AGENCY - United States Coast Guard.

3. DATE - Unknown.

4. APPLICABILITY - The navigable waters of the United States, adjoining shorelines, or the contiguous zone.

5. ADMINISTRATION AND ENFORCEMENT PROVISIONS - This regulation provides for delegation of authority granted by the Federal Water Pollution Control Act and the Water Quality Improvement Act of 1970. The delegations of authority are as follows:

   Secretary of Transportation
   Commandant, U.S. Coast Guard
   District Commanders, USCG
   Any Coast Guard Commissioned, Warrant, and Petty Officer

   These persons have delegated authority to enforce the provisions of Section 311 of the Federal Water Pollution Control Act.

6. HARDWARE REQUIREMENTS - Not applicable.

7. PROCEDURE REQUIREMENTS - Not applicable.

8. DATA REPORTING REQUIREMENTS - Subpart B, Notice of the Discharge of Oil, provides for the reporting of oil discharges as required by the Federal Water Pollution Control Act and the Water Quality Improvement Act of 1970. Any person in charge of a vessel or an onshore or offshore facility, as soon as he has knowledge of any discharge of oil or hazardous substance from the vessel or facility is required to give immediate notice by the most expeditious means available

which includes the use, in order of priority, of telephone, radiotelephone, radio telecommunication or other means of rapid communications. The report should be given to any of the following persons:

- Commanding Officer or Officer-in-Charge of any Coast Guard unit in the vicinity.
- The Commander of the Coast Guard District in which the discharge occurs.
- The Federal Official designated by the Regional Contingency Plan as the On Scene Coordinator (OSC).
- Commandant, U.S. Coast Guard.
- Regional Director of the Federal Water Quality Administration (FWQA).

A table of USCG Districts and FWQA regions is provided along with addresses and telephone numbers.

9. GENERAL COMMENTS - None.

APPENDIX J

SAFETY SHUTDOWN DEVICES

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APPENDIX J
SAFETY SHUTDOWN DEVICES

J.1 INTRODUCTORY SUMMARY

The spill prevention program described in this report relies strongly on safety shutdown devices in the development of spill prevention guidelines. The application of safety shutdown devices, already commonly employed for pipelines and offshore operations, has increased for all petroleum systems as a result of new regulations and attention aimed at reducing petroleum system spillage. Safety shutdown devices primarily have been applied to offshore Production and Gathering/Distribution Systems to protect against personnel injury and facility damage in the event of an abnormal system operation or condition. Additional applications have been made to avoid or reduce the size of oil spills by total or partial shutdown of the system when spill conditions are detected.

Although the safety shutdown devices are responsible for preventing considerable oil spillage, their advantage is partially offset by the fact that they also can malfunction and allow a spill to occur. In particular, high liquid level sensing devices have been identified in Volume I as a priority spill vulnerability point for a number of offshore production subsystems. In general, the spill data of Appendix D lacked definitive failure descriptions on safety shutdown device failures. As a result, additional information was sought.

It was determined that the USGS, through a recently initiated program of safety system inspections, was developing comprehensive and detailed information which would be useful to this study. Through the cooperation of the USGS, the study team was provided with an opportunity to review these data. The findings clarified and substantiated the data of Appendix D on safety subsystem spills. As a result, the findings contributed to the development of the spill vulnerability points and spill prevention guidelines presented in Volume I. This appendix provides guidelines on failure rates and inspection requirements for safety shutdown devices.

Paragraph J.2 presents the functional application and description of the safety shutdown devices studied. Paragraphs J.3 through J.6 present the analyses of pressure sensors, level sensors, surface safety valves, and subsurface safety valves, respectively. The findings are summarized in Paragraph J.7.

J.2 FUNCTIONAL APPLICATION AND DESCRIPTION

J.2.1 Relationship to Safety Subsystems

As described in Appendix B, the safety subsystems (see Figure J-1) protect facilities, equipment, personnel, and wells by providing selective or overall shutdown when operating conditions or parameters exceed previously established limits.

Figure J-1 is applicable to both Production and Gathering/Distribution Systems except for the subsurface safety valves which are used only in Production Systems. The elements of the safety subsystem which are of interest in this appendix are those associated with petroleum system shutdown. Those elements include subsurface safety valves and the elements identified by the functional flow diagram of Figure J-2.

J.2.2 Safety Shutdown Subsystem Elements to be Considered

Referring to Figure J-2, the elements of interest are further defined as follows:

1. Energy Source and Regulator - The types available use electrical, pneumatic, or hydraulic energy. The function of the source is to supply the energy required for surface and subsurface valve control, and for remote control from the various sensing devices. However, since OCS operations employ pneumatic systems predominantly, if not entirely, only pneumatic systems are considered.
2. Sensor and Signal Equipment - Sensors include those for detecting pressure, fire, temperature, and explosive atmosphere liquid level. Of these, consideration is given to high/low pressure sensors and liquid level sensors.
3. Signal Relay Switching Mechanism - This mechanism, also described as a three-way block and bleed valve, acts as a relay and switch. It is activated by a pressure signal in the sensor remote control line, and switches or bleeds

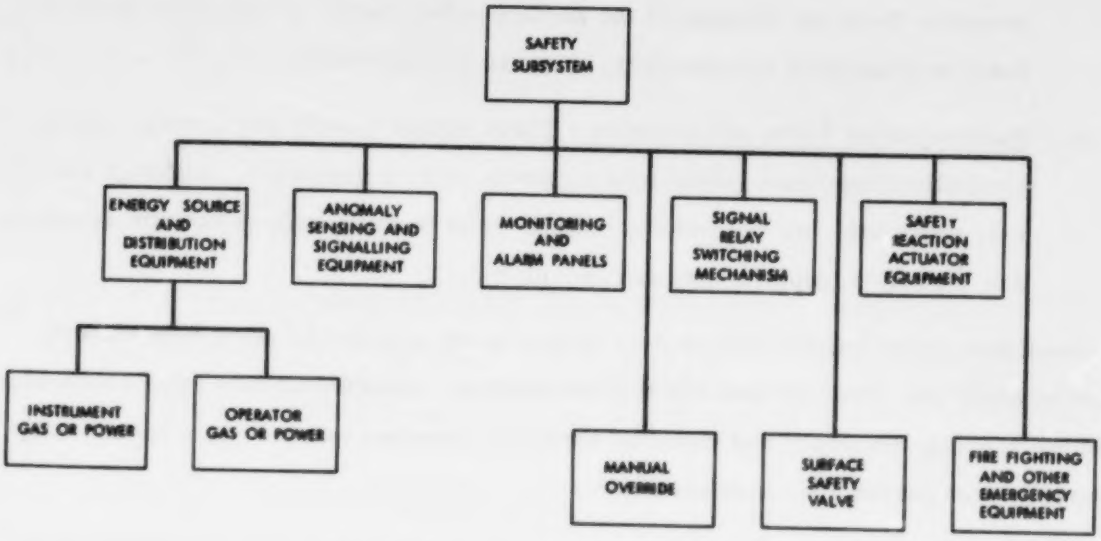
SAFETY SUBSYSTEM
ENERGY SOURCE AND DISTRIBUTION EQUIPMENT
ANOMALY SENSING AND SIGNALLING EQUIPMENT
MONITORING AND ALARM PANELS
SIGNAL RELAY SWITCHING MECHANISM
SAFETY REACTION ACTUATOR EQUIPMENT
INSTRUMENT GAS OR POWER
OPERATOR GAS OR POWER
MANUAL OVERRIDE
SURFACE SAFETY VALVE
FIRE FIGHTING AND OTHER EMERGENCY EQUIPMENT

Figure J-1. Safety Subsystem

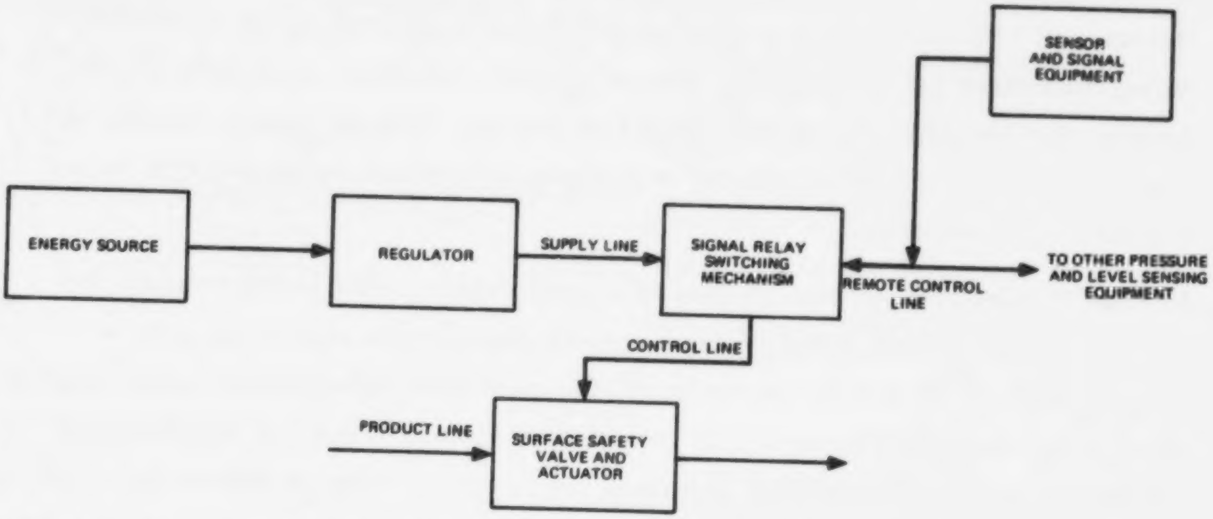
SENSOR AND SIGNAL EQUIPMENT
ENERGY SOURCE
REGULATOR
SUPPLY LINE
SIGNAL RELAY SWITCHING MECHANISM
REMOTE CONTROL LINE
TO OTHER PRESSURE AND LEVEL SENSING EQUIPMENT
CONTROL LINE
PRODUCT LINE
SURFACE SAFETY VALVE AND ACTUATOR

Figure J-2. Partial Functional Flow Diagram of a Sample Safety Shutdown Subsystem

pressure from the actuator of the surface safety valve. No data are given on these mechanisms; consequently, they are not addressed.

4. Surface Safety Valve and Actuator - These valves usually are reverse-acting, normally closed gate valves with a remote control capability. Although electrical, pneumatic, or hydraulic actuators could be used, only pneumatic actuators are identified from the data and considered.

The subsurface safety valves (Figure J-1) include those actuated by down-hole velocity and those which are remotely controlled at the surface. Insufficient data exist concerning use of the recently developed and installed surface-controlled valves. As a result, only the velocity type valves are considered.

For all of the devices under consideration, the study is concerned with only those events in which shutdown should, but does not, occur. Events of false shutdown are not addressed.

J.3 HIGH AND LOW PRESSURE SENSING DEVICES

USGS data were examined for a group of production facilities selected from high production fields in Lafayette District Number 2. The data were generated from December 1971 through June 1972. These data summarize the number of pressure sensor operations during inspections and the number of required pressure resettings, considered as malfunctions for this study, for a population of 1188 sensors. Data for sensors mounted on pressure vessels and sensors installed on pipelines or flowlines are presented in Tables J-1 and J-2, respectively.

Pipeline/flowline pressure sensors generally receive their control energy from the product line. Since the OCS vessel pressure sensors generally use control energy from external sources, the data for the two types of sensors were segregated to permit recognition of any resulting differences. By inspection of Tables J-1 and J-2, reset rates of 130 and 150 reset actions per 1000 operations are observed. From an engineering standpoint this difference is considered not to be significant, since each amounts to approximately one reset for every six operations, or 6 months of operation, assuming monthly inspection is required. OCS Order Number 8 established specific numerical limits for setting both

Table J-1. Failure Rate Data for High/Low Pressure Sensors for Production System Pressure Vessels

General Identification		Pressure Sensors (Pressure Vessels)									
		Number of Operations				Number of Resets			Resets/1000 Operations		
Field Location*	Facility Operator	Population	Hi	Lo	Sub Totals	Hi	Lo	Sub Totals	Hi	Lo	Sub Totals
S. M. I.	B	25	81	57	138	16	13	29	198	228	210
S. M. I.	K	12	28	28	56	4	-	4	143	-	71
S. M. I.	L	66	553	552	1105	59	44	103	107	80	93
E. I.	L	84	442	442	884	5	4	9	11	9	10
S. S.	Q	112	239	217	456	93	71	164	389	327	360
S. S.	R	78	196	190	386	42	53	95	214	279	246
S. T.	G	14	40	40	80	1	-	1	25	-	12
S. T.	H	33	25	25	50	3	2	5	120	80	100
Subtotals		424	1604	1551	3155	223	187	410	139	121	130

*S. M. I. - South Marsh Island
E. I. - Eugene Island
S. S. - Ship Shoal
S. T. - South Timbalier

Table J-2. Failure Rate Data for High/Low Pressure Sensors for Pipelines and Flowlines

General Identification		Pressure Sensors (Pipelines and Flowlines)									
		Number of Operations				Number of Resets			Resets/1000 Operations		
Field Location*	Facility Operator	Population	Hi	Lo	Sub Totals	Hi	Lo	Sub Totals	Hi	Lo	Sub Totals
S. M. I	B	57	138	138	276	39	42	81	283	304	293
S. M. I.	K	8	33	33	66	5	-	5	152	-	76
S. M. I.	L	150	1038	1038	2076	70	79	149	67	76	72
E. I.	L	96	93	93	186	2	1	3	22	11	16
S. S.	Q	175	894	894	1788	185	176	361	207	197	202
S. S.	R	175	260	260	520	69	73	142	265	281	273
S. T.	G	17	41	41	82	-	1	1	-	24	12
S. T.	H	86	90	90	180	15	17	32	167	189	178
Subtotals		764	2587	2587	5174	385	389	774	149	150	150

*S. M. I. - South Marsh Island
E. I. - Eugene Island
S. S. - Ship Shoal
S. T. - South Timbalier

high and low pressure sensors on pressure vessels. This inspection program and frequency appears to be effective since, according to the spill data in Appendix D, relatively few spill events are attributed to pressure sensor malfunction or nonfunction.

J.4 LIQUID LEVEL SENSING DEVICES

The USGS data, selected as described in Paragraph J.3, summarize the number of liquid level sensor operations during inspection and the number of required reset actions, considered as malfunctions for this study, performed for a population of 276 sensors. The data are presented in Table J-3, which indicates that a low rate of reset action was performed, i.e., an average of six actions for each 1000 inspections performed. It is noted, however, that the OCS orders do not specify any criteria for adjustment or reset of liquid level sensors. These inspections appear to be relatively ineffective from the standpoint of spill prevention since, according to the spill data of Appendix D, high liquid level sensors represent one of the most frequently identified items responsible for spills from offshore Production Systems. Consequently, it is concluded that specifying a maximum level limit, with adequate consideration to the shut-in delay time, would prevent a number of high level sensor-associated spill events.

J.5 SURFACE SAFETY VALVES AND ACTUATORS

The USGS data, selected as described in Paragraph J.3, summarize the number of surface safety valve operations during inspections and the number of reset actions, considered as malfunctions for this study, required for a population of 370 valves. The data are presented by Table J-4. According to the data, the average reset rate is low (an average of 18 for 1000 inspections performed). The combined effect of the relatively few resets required and the relative lack of reported spills attributed to the surface safety valves suggest that the inspection program for the devices has been effective. According to the data, weekly inspections were performed; relaxation of this inspection frequency might be considered.

Table J-3. Failure Rate Data for High/Low Liquid Level Sensors for Pressure and Atmospheric Vessels

General Identification		Liquid Level Sensors									
		Number of Operations				Number of Resets			Resets/1000 Operations		
Field Location*	Facility Operator	Population	Hi	Lo	Sub Totals	Hi	Lo	Sub Totals	Hi	Lo	Sub Totals
S.M.I.	B	30	54	40	94	4	-	4	74	-	43
S.M.I.	K	14	50	50	100	-	-	-	-	-	-
S.M.I.	L	56	500	493	993	5	2	7	10	4	7
E.I.	L	65	355	296	651	-	-	-	-	-	-
S.S.	Q	30	24	27	51	1	1	2	42	37	39
S.S.	R	63	150	46	196	-	-	-	-	-	-
S.T.	G	10	40	28	68	-	-	-	-	-	-
S.T.	H	8	8	4	12	-	-	-	-	-	-
Sub-Totals		276	1181	984	2165	10	3	13	8	3	6

*S.M.I. - South Marsh Island
E.I. - Eugene Island
S.S. - Ship Shoal
S.T. - South Timbalier

Table J-4. Failure Rate Data for Surface Safety Valves

General Identification		Surface Safety Valve			
Field Location*	Facility Operator	Population	Number of Operations	Number of Resets	Resets/1000 Operations
S.M.I.	B	27	653	12	18
S.M.I.	K	3	101	6	59
S.M.I.	L	73	1498	20	13
E.I.	L	50	810	26	32
S.S.	Q	84	430	2	5
S.S.	R	86	488	9	18
S.T.	G	8	127	1	8
S.T.	H	39	228	1	4
Totals		370	4335	77	18

*S.M.I. - South Marsh Island
E.I. - Eugene Island
S.S. - Ship Shoal
S.T. - South Timbalier

J. 6 VELOCITY-CONTROLLED SUBSURFACE SAFETY VALVES

USGS data on subsurface safety valve inspections from November 1971 through April 1972 were examined for a group of production facilities selected from seven high-volume production fields.

The data were obtained from semiannual operator reports on subsurface safety valve (SSV) movements for 127 well completions. The combined data included 317 SSV movements identified as "removals" which resulted in the detection of 71 malfunctions. These data are distributed by field and by valve type (expressed as a numerical code to avoid identification of manufacturers) as shown in Tables J-5 and J-6, respectively. In this discussion, only removals are considered. Manfunction is defined for this study as any condition requiring replacement of parts other than safety valve packing material and includes not only worn parts, but parts replaced as a result of changed well conditions. Thus, failures are charged even if the valve itself is operable but requires a different bean size or pressure setting to restore proper function.

Table J-5 shows the facility operations D and H had the greatest number of subsurface safety valve malfunctions. Table J-6 shows that subsurface safety valve codes 1 and 4 presented the most significant contribution to the data, since they represented over 80 percent of the movements and 90 percent of the malfunctions in these data.

As a result, Tables J-7 and J-8 were developed to present code 1 and code 4 subsurface safety valve data from facility operations D and H in terms of the elapsed time (in months) since last valve removal (opportunity to inspect). It is observed from these tables that, of 179 total removals, only 34 (less than 20 percent) occurred over 3 months from the last removal. Out of 35 total failures, 15 (43 percent) of the failures occurred during the same period. The data in Tables J-7 and J-8 were used to develop the reliability function shown in Table J-9. This function takes into account that many removals are for reasons other than subsurface safety valve inspection or maintenance. The valves of cumulative probability of survival shown in Table J-9 are plotted in Figure J-3 and an approximate curve of the reliability function drawn to interpret the points. The reliability function of Figure J-3 indicates that a subsurface safety valve removed 3 months after its last inspection

Table J-5. Distribution of Velocity-Controlled Subsurface Safety Valve Malfunctions and Removals by Month and Facility

Facility Operator	Month												Total	Malfunctions per 1000 Removals
	Nov.		Dec.		Jan.		Feb.		Mar.		Apr.			
	R	M	R	M	R	M	R	M	R	M	R	M	R/M	
L	2	1	1	-	4	-	8	1	9	4	8	4	32/10	312
D	6	1	8	1	3	2	18	12	17	3	9	3	61/22	361
H	16	2	20	1	29	4	16	5	22	4	24	2	127/18	142
G	3	2	4	-	6	1	12	3	2	-	1	-	28/6	214
K	4	-	4	-	2	-	5	-	7	1	11	3	33/4	121
E	4	-	1	-	-	-	2	2	7	3	3	2	17/7	412
J	5	1	2	-	3	-	2	-	4	1	3	2	19/4	210
Total	40	7	40	2	47	7	63	23	68	16	59	16	317/71	224

R = Removal

M = Malfunction

Table J-6. Distribution of Velocity-Controlled Subsurface Safety Valve Malfunctions and Removals by Month and Valve Code

Subsurface Valve Code	Population	Month												Total	Malfunctions per 1000 Removals
		Nov.		Dec.		Jan.		Feb.		Mar.		Apr.			
		R	M	R	M	R	M	R	M	R	M	R	M		
1	53	10	2	16	1	20	4	27	12	26	8	30	7	129/34	264
2	1	-	-	-	-	-	-	-	-	1	-	-	-	1/-	-
3	1	-	-	-	-	-	-	-	-	1	-	-	-	1/-	-
4	49	20	4	18	1	22	3	30	11	25	7	17	5	132/31	235
5	1	-	-	-	-	1	-	1	-	-	-	-	-	2/-	-
6	2	1	-	-	-	-	-	-	-	4	-	-	-	5/-	-
7	1	1	-	1	-	-	-	-	-	-	-	-	-	2/-	-
8	6	4	1	1	-	2	-	-	-	4	-	1	1	12/2	167
9	10	3	-	4	-	2	-	3	-	5	1	10	3	27/4	370
10	1	1	-	-	-	-	-	-	-	-	-	-	-	1/-	-
11	1	-	-	-	-	-	-	1	-	-	-	-	-	1/-	-
12	2	-	-	-	-	-	-	1	-	2	-	1	-	4/-	-
Total	127	40	7	40	2	47	7	63	23	68	16	59	16	317/71	224

R = Removal

M = Malfunction

Table J-7. Distribution of Facility Operation D Codes 1 and 4 Velocity-Controlled Safety Valve Malfunctions (M) and Removals (R) by Elapsed Time Since Last Removal

Subsurface Valve Code	Time Since Last Removal (Months)						
	1	2	3	4	5	6	Total
	R/M	R/M	R/M	R/M	R/M	R/M	R/M
Code 1	25/4	6/1	2/0	7/5	0/0	0/0	40/10
Code 4	10/0	3/1	1/0	6/4	4/2	0/0	24/7

Table J-8. Distribution of Facility Operation H Codes 1 and 4 Velocity-Controlled Safety Valve Malfunctions (M) and Removals (R) by Elapsed Time Since Last Removal

Subsurface Valve Code	Time Since Last Removal (Months)						
	1	2	3	4	5	6	Total
	R/M	R/M	R/M	R/M	R/M	R/M	R/M
Code 1	27/6	4/0	7/1	6/2	0/0	2/0	46/9
Code 4	52/3	5/3	3/1	8/2	1/0	0/0	69/9

Table J-9. Reliability Function for Velocity-Controlled Subsurface Safety Valves

Time Interval Since Last Removal (in Months)	Number of SSVs Downhole at Start of Time Interval	Number of Removals		No Inspection Required	Probability of Survival	
		Condition Good	Condition Discrepant		Interval	Cumulative
0-1	179	101	13	65	.93	.93
1-2	65	13	5	47	.92	.86
2-3	47	11	2	34	.62	.82
3-4	34	14	13	7	.71	.51
4-5	7	3	2	2	1.00	.36
5-6	2	2	0	0	1.00	.36
Totals	334	144	35	155	---	---

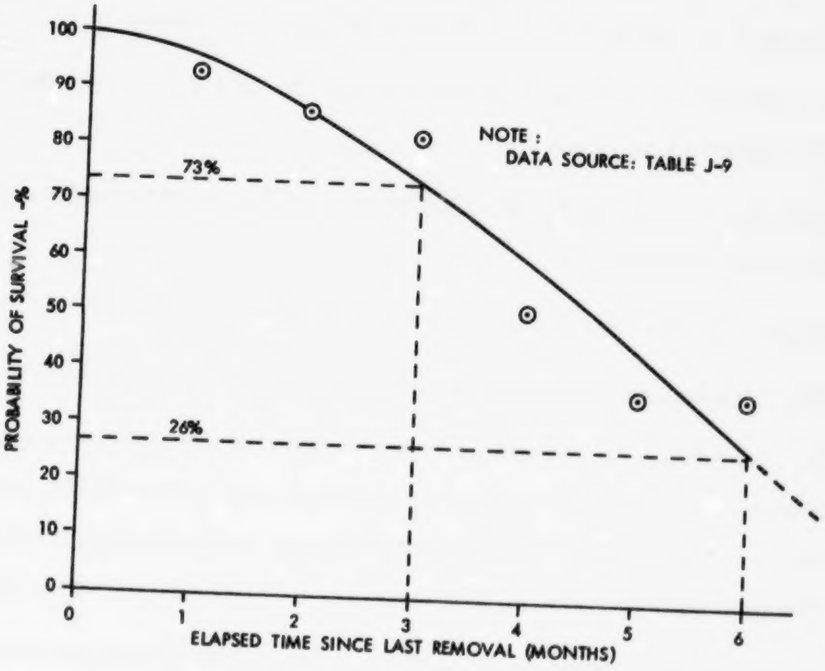

Figure J-3. Estimated Reliability Function for Velocity-Controlled Subsurface Safety Valves would have an estimated probability of 0.73 of being found in working condition and not to need repair or replacement parts. This estimated probability drops to 0.26 when the length of time since last removal is extended to 6 months, the current inspection requirement. A change of inspection frequency from 6 to 3 months could reduce to approximately one-third the expected number of discrepant subsurface safety valves downhole based on the 6-month inspection interval. From the data in Tables J-7 and J-8, approximately 80 percent of the subsurface safety valves are removed, regardless of reason, within 3 months of the last inspection opportunity. Thus, the preceding reduction in discrepant valves would require an apparent 20 percent increase of inspection burden. An increase in subsurface safety valve inspection frequency (possibly in selected areas) should be considered.

J.7 FINDINGS

In general, the study of USGS data on safety shutdown devices:

1. Clarified the safety device failures addressed in Volume I
2. Provided gross average failure rates for the safety shutdown devices addressed in this appendix
3. Substantiated the spill prevention guidelines for safety shutdown devices presented in Volume I

The following specific findings result from the analysis:

1. The frequency of inspection of pressure sensors is reasonable and effective.
2. The low failure rate exhibited by inspections of the high level sensors, considering that these sensors are priority spill vulnerability points addressed in Volume I, is indicative that a maximum high level limit setting should be required and inspected as it is with pressure sensors.
3. The inspection frequency on surface safety valves should be considered for possible relaxation.

4. The inspection frequency of the velocity-controlled subsurface safety valves should be considered for possible increase from the present semiannual requirement to a quarterly requirement.

APPENDIX K

DATA CODE BOOK

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FOREWORD

This Data Code Book has been developed by the Reliability and Effectiveness Assurance Department of Computer Sciences Corporation for use on the Petroleum Systems Reliability Analysis Program which is being conducted for the Environmental Protection Agency. Due to the volume of oil spill data that has been accumulated, it has become necessary to translate the data into a format amenable to machine processing. The codes contained within this Data Code Book were adopted to allow the data (relative to a single oil spill report) to be entered on a standard 80-column IBM card. A specialized data coding sheet was developed to simplify the coding effort. Once coded, the data can be evaluated utilizing Automatic Data Processing techniques.

DATA SYSTEM DESCRIPTION

This Data Code Book forms a key element in the data system established for the Petroleum Systems Reliability Analysis Program. To provide an understanding of the use of this book and its importance within the system, a brief description of the data system is provided here and illustrated in Figure 1.

As oil spills occur within the various jurisdictions of Federal, state, and local government agencies, reports are generated which provide information regarding the circumstances of the spills. These reports are accumulated in various locations throughout the country. Upon receipt at CSC, each spill report is given a unique serial number for filing purposes. Then, using the codes provided herein, the data contained within the spill report are coded onto special coding sheets. (See Figure 2.) After the code sheets have been completed, the original spill reports are filed in serial number order. The information on the code sheets is entered on punched cards. The code sheets are filed and the punched cards forwarded to the Computer Facility. The information on the punched cards is entered into the Computer File, which is stored on magnetic discs. The punched cards are filed in spill report serial number order. The Computer Disc File provides ready access to all available spill report data through automatic data processing techniques.

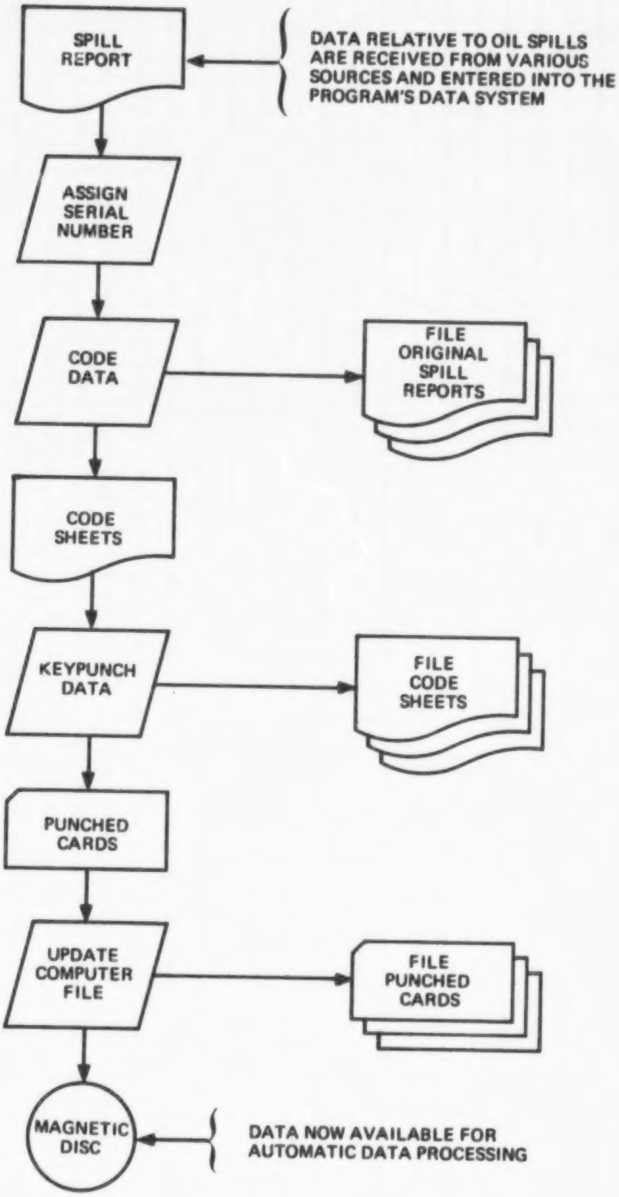
SPILL REPORT
DATA RELATIVE TO OIL SPILLS ARE RECEIVED FROM VARIOUS SOURCES AND ENTERED INTO THE PROGRAM'S DATA SYSTEM
ASSIGN SERIAL NUMBER
CODE DATA
FILE ORIGINAL SPILL REPORTS
CODE SHEETS
KEYPUNCH DATA
FILE CODE SHEETS
PUNCHED CARDS
UPDATE COMPUTER FILE
FILE PUNCHED CARDS
MAGNETIC DISC
DATA NOW AVAILABLE FOR AUTOMATIC DATA PROCESSING

Figure 1. Oil Spill Data Flow Diagram

SHEET NO.______ OF______
DATE________________

						LOCATION CODING																		
	SPILL REPORT SERIAL NUMBER	ASSOCIATED FAILURES		DATA SOURCE	STATE	DISTRICT COUNTY CODE	LEASE NAME GEOGRAPHICAL COORD OFFSHORE BLOCK NO CITY NAME RIVER LAKE BAY	SHORE	LEASE	SPILL DATE Y Y M M D D	ACTIVITY	PRODUCT SPILLED	QUANTITY SPILLED	QUANTITY UNRECOVERED	SPILL DURATION	MULTIPLE FAILURE	CAUSE	SYSTEM SUBSYSTEM EQUIPMENT COMPONENT	PIPE DIAMETER	INSTALLATION DATE	EQUIP PROTECTION	REPAIR ACTION	SPILL CONTROL METHOD	SPILL CLEANUP METHOD	COST	VIOLATION
	1 4	5		11 12	14 15	17 18 19	21 30	32	33	35 40	43 44	46	48 49	51 52	54	56	58 59	61 65	66	67	69	71	73	75	77 78	80
1																										
2																										
3																										
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25																										

Figure 2. Special Purpose Coding Sheet

DATA CODES

The requirement to enter a large quantity of data on a single, 80-column punched card dictated that short alphanumeric codes be utilized. The various data items to be recorded on the punched cards were reviewed and a system of codes devised. These codes, the fields (columns) in which they are to be used, the data item they represent, and a brief discussion of their utility are provided in the following paragraphs and tables.

The field numbers (in numerical sequence) and code titles are shown at the top right corner of each page to facilitate the use of this code book.

Each oil spill event is assigned a unique serial number to identify it for record and reference purposes. This serial number is written on each document which reports the details of an oil spill in Field 1-4 of the code sheet. The serial numbers range from 0001 to 9999, each entry being right justified and zero filled; that is, filling the field. Blocks of serial numbers were initially assigned for coding purposes (gaps intentional) as follows:

Serial Number	Data Source
0001-5373	Texas RR Commission
6000-6125	EPA Headquarters - OHM File
6126-6986	DOT/FRRC
7000-7425	U.S. Geological Survey
7426-8185	Louisiana Conservation Commission
8186-8247	EPA Anchorage, Alaska
8248-8482	Alberta
8483-8596	U.S. Geological Survey
8600-8802	Mississippi
9000-9769	California, New Mexico, Oklahoma and Colorado

FIELD 5
ASSOCIATED FAILURES CODE

Some oil spills involve simultaneous or sequential failures which contribute to that single event. In order to indicate all failures associated with a single oil spill event, a separate coded card is prepared for each failure. On each of these cards the serial number of the spill event is repeated and a code is added in Field 5. All common data is then repeated on each card with only the codes associated with the failed item, cause, et cetera being different. On cards for spill events caused by only one failure, Field 5 is left blank.

Code	Meaning
0	First Failure
1	Second Failure
2	Third Failure
.	.
.	.
.	.
9	Ninth Failure (or more)

DATA SOURCE CODE

Reports of oil spill events are derived from a number of sources. The data source code identifies the origin of the documentation which provides the information on the oil spill event. The data source code assignments are:

Code	Data Source
01	EPA Headquarters - OHM File
02	EPA Anchorage, Alaska
03	ALBERTA - Drilling and Production Monthly Pollution Summaries
04	DOT/FRRC - Pipeline Carrier Accident Reports
05	TEXAS RR Commission
06	U.S. Coast Guard
07	U.S. Geological Survey
08	ALASKA - Department of Conservation
09	LOUISIANA - Conservation Commission
10	CALIFORNIA F&G
11	CALIFORNIA WQCB
12	CALIFORNIA O&G Division
13	CALIFORNIA Long Beach
14	CALIFORNIA Western O&G
15	NEW MEXICO O&G
16	OKLAHOMA Corporation Commission
17	MISSISSIPPI
18	ALBERTA, Edmonton (Pipeline only)
19	COLORADO
20	ARKANSAS

FIELD 14-15
STATE CODE

Petroleum production and gathering/distribution is nationwide. In anticipation of oil spill events being reported from any location, a code is assigned for each State of the United States. Since data were also available from Alberta, Canada, a code was assigned for that Province. The State Code is assigned in recognition of the variations from one jurisdiction to another in policies, codes, rules, and practices relating to the petroleum industry, including the regulation and control of oil spill events.

The code numbers are assigned to correspond to the States as follows:

Code	State	Code	State	Code	State
01	ALABAMA	19	MAINE	37	OREGON
02	ALASKA	20	MASSACHUSETTS	38	PENNSYLVANIA
03	ARIZONA	21	MARYLAND	39	RHODE ISLAND
04	ARKANSAS	22	MICHIGAN	40	SOUTH CAROLINA
05	CALIFORNIA	23	MINNESOTA	41	SOUTH DAKOTA
06	COLORADO	24	MISSISSIPPI	42	TENNESSEE
07	CONNECTICUT	25	MISSOURI	43	TEXAS
08	DELAWARE	26	MONTANA	44	UTAH
09	FLORIDA	27	NORTH CAROLINA	45	VIRGINIA
10	GEORGIA	28	NORTH DAKOTA	46	VERMONT
11	HAWAII	29	NEBRASKA	47	WASHINGTON
12	IDAHO	30	NEVADA	48	WISCONSIN
13	ILLINOIS	31	NEW HAMPSHIRE	49	WEST VIRGINIA
14	IOWA	32	NEW JERSEY	50	WYOMING
15	INDIANA	33	NEW MEXICO	51	ALBERTA, CANADA
16	KANSAS	34	NEW YORK	52	NOT IDENTIFIABLE
17	KENTUCKY	35	OHIO		
18	LOUISIANA	36	OKLAHOMA		

Building upon the State location established in Field 14-15, further refinement is needed to uniquely identify an oil spill event. Most oil-producing states have a Commission or Conservation Board which regulates the industry; many have established districts, county, oil field, or other geographical reference for administration of petroleum production. Oil spill events are reported in accordance with the location reference imposed by State regulation. The code, therefore, provides unique location identification of oil spills. Anticipating the major sources of data on oil spill events and their location, codes have been assigned for Alaska, Alberta, California, Colorado, Louisiana, New Mexico, Oklahoma, and Texas, including offshore areas, where appropriate.

Certain data banks are on a national basis and some data does not include detailed location information for all states. These sources, namely, EPA Headquarters, DOT/FRRC, and USGS, cover 43 States. The coding for states not listed above usually refers to the location by naming the county within the State where the oil spill event occurred. Where location codes have been established, the applicable events from the national data banks are coded in accordance with the local scheme. Because of the unique nature of reporting data in each State, an explanation of location coding immediately precedes the code list for each of the above States.

It appears fairly definite that no data on oil spill events would be obtained from operations on the Alaskan North Slope, Prudhoe Bay. Hence, the appropriate code in Field 17-18 is used to locate oil spill events to the Swanson River Field or to the various fields in and near Cook Inlet.

Current petroleum production is concentrated in the Cook Inlet and surrounding area.

Specific codes have not been included here so that proprietary rights are protected, in accordance with previous agreements.

In California, the Oil and Gas Commission has divided the state into six oil and gas districts. A three-digit number code is used to identify the district and county within the district; these three digits occupy Field 17-19 on the coding sheet. Further refinement of location is given by entries in Field 21-30; one of three generalized categories is used in "placing" the spill, namely, in preferred order:

1. Oil Fields
2. Cities
3. Physiographic features (rivers, canyons) and generalized geographical-geological areas (Los Angeles Basin, Hollywood Hills, etc.).

Unless the data bank names a specific oil field as the origin of the spill, city codes are used, when possible, to locate the incidents. Therefore, the city codes include spills at docks and wharfs and those of unknown origin (i.e., ran out of storm drain) which were first observed on waters under the city's jurisdiction. When spill locations are vague, generalized geographical descriptions are used.

The location code for Field 21-30, which covers the recorded events, follows the listing of the codes for Field 17-19.

DISTRICT 1

Code	County
101	Imperial
102	Los Angeles
103	Orange
104	Riverside
105	San Bernardino
106	San Diego

DISTRICT 2

Code	County
201	Ventura

DISTRICT 3

Code	County
301	Monterey
302	San Benito
303	San Luis Obispo
304	Santa Barbara
305	Santa Clara
306	Santa Cruz

DISTRICT 4

Code	County
401	Kern
402	Tulare
403	Inyo

DISTRICT 5

Code	County
501	Fresno
502	Kings
503	Madera
504	Mariposa
505	Merced
506	Mono
507	Stanislaus
508	Toulumne

DISTRICT 6

Code	County
601	Alameda
602	Alpine
603	Amador
604	Bulte
605	Calaveras
606	Colusa
607	Contra Costa
608	Del Norte
609	El Dorado
610	Glenn
611	Humboldt
612	Lake
613	Lassen
614	Marin

DISTRICT 6 (Cont'd)

Code	County
615	Mendocino
616	Modoc
617	Napa
618	Nevada
619	Placer
620	Plumas
621	Sacramento
622	San Francisco
623	San Joaquin
624	San Mateo
625	Shasta
626	Sierra
627	Siskiyou
628	Solano
629	Sonoma
630	Sutter
631	Tehama
632	Trinity
633	Yolo
634	Yuba

OFFSHORE AREAS

Code	Name
011	State Waters
012	Federal Waters
013	City Jurisdiction Waters

CODE	GENERALIZED GEOGRAPHIC LOCATION
CARQUINEZ	Carquinez Straits, near San Francisco
HOLLYWDHLS	Hollywoods Hills, north of Los Angeles
LABASIN	Unspecified locations within Los Angeles Basin (Geologic Feature)
MADRONOCRK	Madrono Creek, near Ventura
MORROBAY	Morro Bay, near San Luis Obispo
SALINASRIV	Salinas River, near Salinas
SNACLARARV	Santa Clara River, near Castaic Junction
TERMINALIS	Terminal Island, Long Beach
VENTURAAVE	Ventura Avenue, within northern suburbs of Los Angeles
WILEYCANYN	Wiley Canyon, near Newhall

COLORADO LOCATION CODE

The Oil and Gas Commission of Colorado has not divided the state into districts. Since the data refers to counties, a three-digit number code is used for entry in Field 17-19. When given, geographical coordinates will be entered in Field 21-30.

Code	County	Code	County	Code	County
101	Adams	122	Fremont	143	Montrose
102	Alamosa	123	Garfield	144	Morgan
103	Arapahoe	124	Gilpin	145	Otero
104	Archuleta	125	Grand	146	Ouray
105	Baca	126	Gunnison	147	Park
106	Bent	127	Hinsdale	148	Phillips
107	Boulder	128	Huerfano	149	Pitkin
108	Chaffee	129	Jackson	150	Prowers
109	Cheyenne	130	Jefferson	151	Pueblo
110	Clear Creek	131	Kiowa	152	Rio Blanco
111	Conejos	132	Kit Carson	153	Rio Grande
112	Costilla	133	Lake	154	Routt
113	Crowley	134	La Plata	155	Saguche
114	Custer	135	Larimer	156	San Juan
115	Delta	136	Las Animas	157	San Miguel
116	Denver	137	Lincoln	158	Sedgwick
117	Dolores	138	Logan	159	Summitt
118	Douglas	139	Mesa	160	Teller
119	Eagle	140	Mineral	161	Washington
120	Elbert	141	Moffat	162	Weld
121	El Paso	142	Montezuma	163	Yuma

FIELD 17-30
LOUISIANA LOCATION CODE

The Conservation Commission of Louisiana has divided the State into six districts. All petroleum information, incident to petroleum production, is routed via an appropriate district office. Since a great deal of petroleum industry activity takes place off the Louisiana coast, the Conservation Commission has assigned area names and block numbers within a given area.

Three-digit number codes are used for each district, for parishes within districts, and for each of the Louisiana offshore areas. Since all offshore oil spill events are reported to the appropriate (nearest) onshore parish, only district and parish codes are entered in Field 17-19. Further location refinement of an offshore spill event is accomplished by entry of the three-digit offshore area code in Field 21-12, the letters BLK in Field 24-26, and the one-, two- or three-digit block number in Field 28-30.

For onshore spill events, location is sufficiently pinpointed by entry of the oil field name in the Field 21-30.

LOUISIANA PARISHES BY CONSERVATION DISTRICTS

SHREVEPORT DISTRICT

Code	Parish
101	Bienville
102	Bossier
103	Caddo
104	Claiborne
105	DeSoto
106	Jackson
107	Lincoln
108	Natchitoches
109	Red River
110	Sabine

SHREVEPORT DISTRICT (Cont'd)

Code	Parish
111	Vernon (north)
112	Webster
113	Winn

MONROE DISTRICT

Code	Parish
201	Avoyelles (north)
202	Caldwell
203	Catahoula
204	East Carroll

LOUISIANA PARISHES BY CONSERVATION DISTRICTS (Cont'd)

MONROE DISTRICT (Cont'd)

Code	Parish
205	Franklin
206	Grant
207	La Salle
208	Madison
209	Morehouse
210	Ouachita
211	Rapides (north)
212	Richland
213	Union
214	West Carroll
215	Concordia
216	Tennas

LAKE CHARLES DISTRICT

Code	Parish
301	Allen
302	Beauregard
303	Calcasieu
304	Cameron
305	Jefferson Davis
306	Vernon (south)

LAFAYETTE DISTRICT

Code	Parish
401	Acadia
402	Avoyelles (south)
403	Evangeline
404	Iberia
405	Iberville (northwest)
406	Lafayette
407	Pointe Coupee
408	Rapides (south)
409	St. Landry
410	St. Mary
411	St. Martin (west)
412	Vermillion

HOUMA DISTRICT

Code	Parish
501	Ascension (south)
502	Assumption
503	Iberville (south)
504	Lafourche
505	St. Charles
506	St. James
507	St. John the Baptist
508	St. Martin (east)
509	Terrebonne

LOUISIANA PARISHES BY CONSERVATION DISTRICTS (Cont'd)

NEW ORLEANS DISTRICT

Code	Parish
601	Ascension (north)
602	East Baton Rouge
603	East Feliciana
604	Iberville (northwest)
605	Jefferson
606	Livingston
607	Orleans
608	Plaquemines
609	St. Bernard
610	St. Helena
611	St. Tammany
612	Tanygipachoa
613	Washington
614	West Baton Rouge
615	West Feliciana

LOUISIANA OFFSHORE AREAS

Code	Name
011	West Cameron
012	East Cameron
013	Vermilion
014	South Marshall Island
015	Rabbit Island Dome
016	Eugene Island
017	Ship Shoal

LOUISIANA OFFSHORE AREAS (Cont'd)

Code	Name
018	Bay Marchand
019	South Timbalier
020	South Pelto
021	Grand Isle
022	West Delta
023	South Pass
024	Main Pass
025	Breton Sound
026	Chandeleur Sound
027	State Lease 340

The county name is the best information available for fixing the location of oil spills in Mississippi. Hence, the code for Mississippi, entered in Fielf 17-30 on the coding sheet, is the county name. If the county name is not given, the name of the oil field may be entered, if available.

FIELD 17-30
NEW MEXICO LOCATION CODE

The New Mexico Oil Conservation Commission has divided the state into four districts. A three-digit number code is used to identify location to counties by districts. This code is entered in Field 17-19. Oil spills are reported by geographical coordinates, which are entered in Field 21-30 as a refinement of the location of the event.

DISTRICT 1

Code	County
101	Chaves
102	Curry
103	Lea
104	Roosevelt

DISTRICT 2

Code	County
201	Chaves
202	De Boca
203	Dona Ava
204	Eddy
205	Lincoln
206	Otero

DISTRICT 3

Code	County
301	McKinley
302	Rio Arriba
303	Sandoval
304	San Juan

DISTRICT 4

Code	County
401	Bernalillo
402	Catron
403	Colfax
404	Grant
405	Guadalupe
406	Harding
407	Hildalgo
408	Luna
409	Mora
410	Quary
411	San Miguel
412	Santa Fe
413	Sierra
414	Socorro
415	Taos
416	Torrance
417	Union
418	Volencia

The Oil and Gas Conservation Division of the Oklahoma Corporation Commission has divided the State into four districts and established a statewide geographical grid. Oil spill events are located and reported in accordance with this grid. A three-digit number code is used to fix location by district and county; this code fills Field 17-19 on the coding sheet. The geographical coordinates of the oil spill events are coded in Field 21-30.

DISTRICT 1

Code	County
101	Adair
102	Cherokee
103	Craig
104	Creek
105	Delaware
106	Kay
107	Lincoln
108	Mayes
109	Muskogee
110	Noble
111	Nowata
112	Okfuskee
113	Okmulgee
114	Osage
115	Ottawa
116	Pawnee
117	Payne
118	Rogers
119	Tulsa

DISTRICT 1 (Cont'd)

Code	County
120	Wagoner
121	Washington

DISTRICT 2

Code	County
201	Alfalfa
202	Beaver
203	Blaine
204	Canadian
205	Cimarron
206	Custer
207	Dewey
208	Ellis
209	Garfield
210	Grant
211	Harper
212	Kingfisher
213	Logan
214	Major

DISTRICT 2 (Cont'd)

Code	County
215	Oklahoma
216	Roger Mills
217	Texas
218	Woods
219	Woodward

DISTRICT 3

Code	County
301	Beckham
302	Caddo
303	Carter
304	Cleveland
305	Comanche
306	Cotton
307	Garvin
308	Grady
309	Greer
310	Harmon
311	Jackson
312	Jefferson
313	Kiowa
314	Love
315	McClain
316	Murray
317	Stephens
318	Tillman
319	Washita

DISTRICT 4

Code	County
401	Atoka
402	Bryan
403	Choctow
404	Coal
405	Haskell
406	Hughes
407	Johnston
408	Latimer
409	Le Flore
410	McCurtain
411	McIntosh
412	Marshall
413	Pittsburh
414	Pontotoc
415	Pottawatomie
416	Pushmataha
417	Seminole
418	Sequoyah

The Texas Railroad Commission, Oil and Gas Division, has divided the state into 12 districts and has designated off-shore locations by name and block number. A three-digit number code is used to locate the district and county. This code is entered in Field 17 - 19 on the coding sheet. The pertinent oil field name is entered in Field 20 - 30.

Crude oil activity off-shore Texas during the 1970-71 period was not sufficient to study. Hence, no off-shore codes are provided.

DISTRICT 1

Code	County
101	Atacosca
102	Bandera
103	Bastrop
104	Bell
105	Bexer
106	Blanco
107	Burnet
108	Caldwell
109	Comal
110	Dummit
111	Edwards
112	Frio
113	Gillespie
114	Gonzales
115	Guadalupe
116	Hays
117	Kendall
118	Kerr
119	Kinney

DISTRICT 1 (Cont'd)

Code	County
120	La Salle
121	Llano
122	Mason
123	Maverick
124	Mc Mullen
125	Medina
126	Milam
127	Real
128	Travis
129	Ulvalde
130	Val Verde
131	Williamson
132	Wilson
133	Zavala

DISTRICT 2

201	Bee
202	Calhoun
203	DeWitt

DISTRICT 2 (Cont'd)

Code	County
204	Goliad
205	Jackson
206	Karnes
207	Lavaca
208	Live Oak
209	Refugio
210	Victoria

DISTRICT 3

Code	County
301	Austin
302	Brazoria
303	Brazos
304	Burleson
305	Chambers
306	Colorado
307	Fayette
308	Fort Bend
309	Galveston
310	Grimes
311	Hardin
312	Harris
313	Jasper
314	Jefferson
315	Lee
316	Liberty
317	Madison

DISTRICT 3 (Cont'd)

Code	County
318	Matagorda
319	Montgomery
320	Newton
321	Orange
322	Polk
323	San Jacinto
324	Trinity
325	Tyler
326	Walker
327	Waller
328	Washington
329	Wharton

DISTRICT 4

Code	County
401	Aransas
402	Brooks
403	Cameron
404	Duval
405	Hidalgo
406	Jim Hogg
407	Jim Wells
408	Kenedy
409	Kleberg
410	Nueces
411	San Patricio
412	Starr

DISTRICT 4 (Cont'd)

Code	County
413	Webb
414	Willacy
415	Zapata

DISTRICT 5

Code	County
501	Bosque
502	Collin
503	Dallas
504	Delta
505	Ellis
506	Falls
507	Fannin
508	Freestone
509	Henderson
510	Hill
511	Hopkins
512	Hunt
513	Johnson
514	Kaufman
515	Lamaer
516	Leon
517	Limestone
518	Navarro
519	Mc Lennan
520	Rains
521	Robertson

DISTRICT 5 (Cont'd)

Code	County
522	Rockwell
523	Tarrant
524	Van Zandt

DISTRICT 6

Code	County
601	Anderson
602	Angelina
603	Bowie
604	Camp
605	Cass
606	Cherokee
607	Franklin
608	Gregg
609	Harrison
610	Houston
611	Marion
612	Morris
613	Nacogdoches
614	Panola
615	Red River
616	Rusk
617	Sabine
618	San Augustine
619	Shelby
620	Smith
621	Titus

DISTRICT 6 (Cont'd)

Code	County
622	Upshur
623	Wood

DISTRICT 7

Code	County
701	Brown
702	Callahan
703	Coleman
704	Comanche
705	Coryell
706	Eastland
707	Erath
708	Fisher
709	Hamilton
710	Haskell
711	Hood
712	Jones
713	Lampasas
714	Mills
715	Nolan
716	Palo Pinto
717	Parker
718	San Saba
719	Shakelford
720	Somervell
721	Stephens
722	Stonewall
723	Taylor
724	Throckmorton

DISTRICT 7 C

Code	County
750	Coke
751	Concho
752	Crockett
753	Irion
754	Kimble
755	McCulloch
756	Menard
757	Reagan
758	Runnels
759	Schleicher
760	Sutton
761	Terrell
762	Tom Green
763	Upton

DISTRICT 8

Code	County
801	Andrews
802	Brewster
803	Crane
804	Culberson
805	Ector
806	El Paso
807	Glassock
808	Howard
809	Hudspeth
810	Jeff Davis

DISTRICT 8 (Cont'd)

Code	County
811	Loving
812	Martin
813	Midland
814	Mitchell
815	Pecos
816	Presidio
817	Reeves
818	Sterling
819	Ward
820	Winkler

DISTRICT 8 A

Code	County
850	Bailey
851	Bordon
852	Cochran
853	Cottle
854	Crosby
855	Dawson
856	Dickens
857	Floyd
858	Gaines
859	Garza
860	Hale
861	Hockley
862	Kent
863	King

DISTRICT 8 A (Cont'd)

Code	County
864	Lamb
865	Lubbock
866	Lynn
867	Motley
868	Scurry
869	Terry
870	Yoakum

DISTRICT 9

Code	County
901	Archer
902	Baylor
903	Clay
904	Cooke
905	Denton
906	Foard
907	Grayson
908	Hardeman
909	Jack
910	Knox
911	Montague
912	Wichita
913	Wilbarger
914	Wise
915	Young

DISTRICT 10

Code	County
950	Armstrong
951	Briscoe
952	Carson
953	Castro
954	Childress
955	Collingsworth
956	Dallam
957	Deaf Smith
958	Donley
959	Gray
960	Hall
961	Hansford
962	Hartley
963	Hemphill
964	Hutchinson
965	Lipscomb
966	Moore
967	Ochiltree
968	Oldham
969	Parmer
970	Potter
971	Randall
972	Roberts
973	Sherman
974	Swisher
975	Wheeler

The Canadian Province of Alberta is divided into five areas. It is further divided in the north/south direction by meridians 4, 5, and 6 and still further subdivided into an east/west and south/north grid. In addition, oil fields are named. All oil spill events in Alberta are reported using this system to identify the location. For coding purposes, a system has been devised to utilize the Canadian grid system. The code consists of a six-digit code followed by the oil field name.

The first digit to be entered in Field 17 indicates the involved area of the five major areas in ALBERTA, as determined by the Oil and Gas Conservation Board.

Code	Area
1	Edmonton
2	Drayton Valley
3	Red Deer
4	Black Diamond
5	Medicine Hat

The remaining series of numbers are geographical coordinates, which are measured from east to west and from south to north. The first coordinate number, to be entered in Field 18, is one of the three digits, 4, 5, or 6, indicating that meridian to the west of which the spill occurred; the 4th meridian coincides with the eastern longitude boundary of Alberta. The next two digits, to be entered in Field 19-20, indicate the range to the west of the pertinent meridian (4, 5, or 6); these digits will be between 01-30. The meridian and range numbers constitute a "longitude" measure. The next digits (1, 2, or 3) indicates the township number measured from the southern boundary of Alberta; this number provides a "latitude" measure of the location and will be between 1-126.

An example of coding an oil spill at Redwater follows:

Code	Meaning
1	Edmonton Area
4	West of 4th Meridian
21	Range, Block 21 Measured West of 4th Meridian
57	Township, Block 57 North of Southern Boundary of Alberta

Hence, the code goes: 142157 REDWATR. The name of the field is abbreviated to fit the remaining available spaces. The "name" shall be coded the same for all incidents reported against that particular field.

A major division in the petroleum industry is represented by onshore versus offshore production. The governing laws and regulations are different in each case; factors such as the types of equipment and the configuration of wells, vary to a large degree. Offshore is interpreted to mean the seaward areas outside the low tide mark of the coasts of the United States. Onshore is interpreted to mean the land territory of the U.S. inside the low tide mark and including lakes and rivers.

The shore code is as follows:

Code	Definition
1	On-shore
2	Off-shore

Petroleum production is controlled under a variety of lease arrangements. It is considered pertinent to the study to note under what type of lease the crude oil production occurred. Accordingly, the following lease code is used:

Code	Lease
1	Federal
2	State
3	Indian Land
4	Canadian
5	Private
6	Cannot Be Determined
7	Pipeline

FIELD 35-40
SPILL DATE CODE

For each identified oil spill event it is necessary not only to locate where it occurred but also to note the time of occurrence. It is considered that recording the year, month, and day is adequate for the study. Sorting of data is facilitated by ordering from left to right: (1) last two digits of the year, (2) two digits for the month, and (3) two digits for the day of the month. Each entry shall completely fill this data field using zeros as appropriate for the months and days having less than two digits in normal representation.

The spill date code is to be entered in accordance with the following illustration:

35	36	37	38	39	40
Year		Month		Day	
Y	Y	M	M	D	D

The petroleum industry activities compiled in this study are divided into gathering/distribution, production (each of which include some storage activity), and Drilling. To support some analyses, it was considered appropriate to further subdivide these activities as indicated by the following activity codes:

Code	Activity
01	Normal Operation (Details unknown)
02	Normal Operation-Tended
03	Normal Operation-Untended
04	Normal Operation-Automatic
05	Preventive Maintenance
06	Unscheduled Repair/Maintenance
07	Test and Inspection
08	Installation
09	Wireline Operation
11	Not Reported
12	Completion
13	Workover
14	Abandoned
15	Water Injection

FIELD 46
PRODUCT SPILLED CODE

It may be desirable to evaluate events of interest, other than crude oil spills, related to petroleum production. To verify that a particular oil spill event involves crude oil and to distinguish the other products that may be coded in an event worthy of note. The following product spilled code is provided:

Code	Product Spilled
1	Crude Oil
2	Water
3	Gas
4	Refined Petroleum Products
5	LPG
6	Condensate
7	Other Hazardous Material
8	Not Specified

FIELD 48-49
QUANTITY SPILLED CODE
FIELD 51-52
QUANTITY UNRECOVERED CODE

Spills are classified as minor (less than 100 gallons); moderate (100-10,000 gallons); or major (10,000 or more gallons). However, the quantity is usually more closely estimated for most spill events and it is considered appropriate to reflect this by subdividing these three major categories. Therefore, certain ranges within each category have been adopted to refine the classification of data as regards quantity spilled. In many spill events much oil is recovered, leaving a quantity of unrecovered oil. A measure of the environmental impact is the quantity of unrecovered oil. As a result, in addition to the quantity spilled, it was decided to code the quantity unrecovered to provide that measure of environmental impact.

The oil industry uses barrels as its unit of measure; therefore, this measure was adopted as the unit of measure to be recorded by coding. One barrel equals 42 gallons.

The quantity code is used to report the spills and the unrecovered crude oil are:

Code	Minor Spill (BBLS)
01	0 - 1.0
02	1.1 - 2.5

Code	Moderate Spill (BBLS)
13	2.6 - 10
14	11 - 100
15	101 - 238

Code	Major Spill (BBLS)
25	239 - 500
26	501 - 1,000
27	1,001 - 5,000
28	5,001 - 10,000
29	10,001 or more

Code	
41	Not Reported
42	Cannot be Determined (Data Ambiguous)

SPILL DURATION CODE

The spill duration code indicates the length of time, in hours, that the pollutant was flowing into the environment. Lengthy spills detract from the satisfactory operating time of the petroleum system, indicate maintainability problems, and give an indication of the adequacy of inspection and monitoring practices. For analysis of failures, the duration of the spill events is deemed important. Accordingly, the following spill duration code is used:

Code	Hours
1	0-6
2	7-12
3	13-18
4	19-24
5	25-48
6	49-72
7	73-96
8	Over 96
9	Not Reported

FIELD 56
MULTIPLE FAILURES CODE

The reported cause of an oil spill event may be simple or compound. A sequence of events may be involved in which several systems or equipments contribute to a series of failures or there may have been only a single failure. When multiple failures are reported for an oil spill event, multiple line entries are prepared containing unique information for each failure. This code identifies each such record and is related to the entry in Field 5.

The multiple failure code is:

Code	Description
1	Multiple Failures
2	No Multiple Failures
3	Possible Multiple Failures But Cannot Tell From Data

Information of varying degrees of completeness is reported in connection with oil spill events. From this information the cause may be assessed. A 2-digit code system is used to record these causes. The code selected should reflect the cause of the equipment or system failure and answer the question "How did it fail?", not "What failed?" The code has been structured to reflect a variety of causes reported. For example, it may have been reported that a person was responsible; in another case that it was an environmental factor; or another, that the equipment was deficient in some respect. The causes have been grouped in major categories, as listed below.

Code	Major Cause
01-03	Unknown
04	Blowout
10-39 & A1	Equipment Failure
40-55	Operator/Maintenance Error
90-99	Third Party
70-81	Natural Causes
60-64	Engineering Error

These categories have been further refined in the following lists. The cause which most nearly reflects the primary cause stated in the spill report should be selected and entered in Field 58-59.

Code	Cause
01	Unknown
02	No Malfunction
03	Not Reported
04	Blowout (Well Blew)
10	Equipment Failure
11	Binding
12	Broken
13	Burned
14	Burst/Ruptured/Split
15	Corroded
16	Corroded, Externally
17	Corroded, Internally
18	Cut, Flow
19	Cut, Sand
20	Defect, Material
21	Electrical Malfunction
22	Failure Opened
23	Failure Closed
24	Frozen & Burst
25	Hole
26	Leaking
27	Lost Instrument Gas
28	Manufacturer's Defect
29	Missing Hardware
30	Non Functioning
10	Equipment Failure
31	Overflowed
32	Overpressure
33	Parted, Line or Union
34	Plugged
35	Power Loss, Electrical
36	Sanded Up
37	Seized/Jammed
38	Vibration
39	Weld, Defective
A1	Worn
40	Operator/Maintenance Error
41	Adjustment or Alignment, Improper
42	Application, Wrong
43	Assembled, Improperly
44	Deactivated or Removed (for Maintenance, Modification, or Test)
45	Handling Damage
46	Installation, Improper
47	Left Closed
48	Left Open
49	Lubrication, Improper
50	Maintenance, Improper
51	Operation, Incorrect

FIELD 58-59
CAUSE CODE
(Cont'd)

Code	Cause
40	Operator/Maintenance Error
52	Pressure, Deficient
53	Pressure, Over
54	Safety Violation
55	Tools, Faulty or Improper
60	Engineering Error
61	Design
62	Application
63	Layout
64	Unstable Adjustment
70	Natural Causes
71	Earthquake
72	Fire
73	Flood
74	Rain
75	Ice Floes
76	Landslide
77	Lightning
78	Marine Growth
79	Temperature
80	Ice & Snow
81	Wind, High
82	Well Kicked
83	Well Flowed

Code	Cause
90	Third Party
91	Boat Anchor
92	Collision
93	Farm Machinery
94	Foreign Object Damage
95	Live Stock
96	Road Machinery
97	Unknown
98	Valve Was Opened/Closed
99	Vandalism

FIELD 61-65
SYSTEM CODE

For this study, Crude Oil Systems are divided into three basic system groupings: Drilling, Gathering/Distribution, and Production. The latter two include a storage function. Study of the functional configuration of each of these systems has led to the designation of subsystems, equipment within subsystems, and generic components that appear likely to be associated with anticipated equipment failures or problems.

The system code is designed to report the system, subsystem, equipment, and component involved in each oil spill event. It is desired that the failure involved in each oil spill be identified to all of these levels. However, where this is not possible, the failures should be identified to the full extent of information provided by the data sources. The system code is a 5-digit code structured within Field 61-65 as follows:

61	62	63	64	65
System	Subsystem	Equipment	Component	

The codes for system, subsystem, and equipment are single digit, whereas the code for components is two digits. Where information is lacking at a given level, the particular code space shall be filled with a zero, or two zeros in the case of components. The codes are listed in the following four lists; one each for Gathering/Distribution, Drilling, and Production Systems (which includes structured subsystem and equipment listings), and a fourth for components. The component codes replace the last two zeros in the codes from the previous lists where components can be identified.

Code	System/Subsystem/Equipment
10000	GATHERING/DISTRIBUTION
11000	Pipeline S/S
11100	Pipe
11200	Scraper Trap Equipment
11300	Pipe Supporting Structure
11400	Stream Crossing
11500	Road Crossing
12000	Storage S/S
12100	Tank
12200	Tank Fire Walls
12300	Tank Associated Equipment
12400	Power
13000	Pump Station S/S
13100	Pump
13200	Centrifugal Pump
13300	Reciprocating Pump
13400	Manifold
13500	Rotary Pump
13600	Steam Engines
13700	Gas Turbine
13800	Steam Turbine
13900	Internal Combustion Engine
13A00	Electric Motors
13B00	Pressure Controllers
13C00	Metering Equipment
13D00	Valve
13E00	Valve Operating Equipment/ Controls
13F00	Electric Power and Control
13G00	Communication Equipment
13H00	Drainage System
13J00	Power
14100	Safety S/S
14100	Pressure Sensing
14200	Pressure Switching
14300	Flow and Guage Indicating Equipment
14400	Temperature Recorders
14500	Power
1500	Gathering Pipelines S/S
15100	Gravity
15200	Suction
15300	Pressure
20000	DRILLING
21000	Well S/S
21100	Hole
21200	Casing String
21300	Casing Head
21400	Cement

Code	System/Subsystem/Equipment
20000	DRILLING (Cont'd)
22000	Prime Power S/S
22100	Engines
22200	Power Transfer
23000	Hoisting & Rotating S/S
23100	Derrick Platform
23200	Crown Block
23300	Traveling Block
23400	Draw Works
23500	Elevators
23600	Drilling Line
23700	Rotary Hook
23800	Rotary Table
23900	Floor Tools
24000	Mud S/S
24100	Mud Pit
24200	Suction Line
24300	Mud Pump
24400	Mud Line
24500	Stand Pipe
24600	Rotary Hose
24700	Mud Flow Line
24800	Shale Shaker
24900	Atmospheric Degasser
24A00	Vacuum Degasser
24B00	Desander
24C00	Desilter
24D00	Barite Recovery Unit (Centrifuge)
24E00	Mud Mixing & Treating
24F00	Mud Monitoring Instruments
25000	Drilling String S/S
25100	Swivel
25200	Kelly
25300	Kelly Cock
25400	Drill Pipe
25500	Drill Collars
26000	Blow Out Preventer S/S
26100	Pipe Ram BOP
26200	Blind Ram BOP
26300	Annular (Bag Type) BOP
26400	Down Hole BOP
26500	Accumulator & Lines (Closing Unit)
26600	Energy Supply
26700	Choke Manifold & Special Kill Equipment
27000	Utility S/S
27100	Air

Code	System/Subsystem/Equipment
20000	DRILLING (Cont'd)
27000	Utility S/S
27200	Steam
27300	Electrical
27400	Water
30000	PRODUCTION
31000	Well S/S
31100	Bore
31200	Casing String
31300	Production Tubing
31400	Downhole Assembly
32000	Well Head S/S
32100	Casing Head Equipment
32200	Tubing Head Equipment
32300	Choke, Fixed
32400	Choke, Adjustable
32500	Rod Pump
32600	Hydraulic Lift
32700	Gas Lift
32800	Electrical Pump
32900	Power
33000	Gathering S/S
33100	Flow Line Equipment
33200	Choke, Fixed
33000	Gathering S/S
33300	Choke, Adjustable
33400	Manifold
33500	Metering
33600	Pumps
33700	Automatic Control Equipment
33800	Power
3400	Separation S/S
34100	Separators, High Pressure
34200	Separators, High Controls
34300	Separators, Low Pressure
34400	Separators, Low Controls
34500	Scrubber
34600	Scrubber Controls
35000	Treater S/S
35100	Heater Treater
35200	Heater Treater Controls
35300	Chemical-Electrical Treater
35400	Chemical-Electric Controls
35500	Gun Barrel
35600	Skimmer (Settling)
35700	Free-Water Knockout
35800	Power

Code	System/Subsystem/Equipment
20000	PRODUCTION (Cont'd)
36000	Local Storage S/S
36100	Tanks
36200	Tank Associated Equipment
36300	Sump System
36400	Firewall
36500	Power
37000	Custody Transfer S/S
37100	Pumps
37200	Pump Controls
37300	Metering Equipment
37400	Manifold
37500	Sampling Equipment
37600	Prover Tank
37700	Power
38000	Safety Shutdown & Alarm S/S
38100	Energy Source
38200	Energy Source Distribution Equipment
38300	Sensing or Detecting Equipment
38400	Monitoring and Alarm Panels
38500	Electrical Equipment
38600	Subsurface Safety Valve
38700	Surface Controlled Subsurface Safety Valve
38800	High/Low Pressure Valve
39000	Water Disposal or Injection S/S
39100	Power
39200	Precipitator

FIELD 61-65
SYSTEM CODE
(Cont'd)

Code	Component
01	Bell, Alarm
02	Bellows
03	Blowcase, Saltwater
04	Bourdon
05	Box, Stuffing
06	Cable
07	Choke Bean
08	Choke Body
09	Choke Target
10	Coil
11	Connector, Electrical
12	Coupling
13	Detector, Gas
14	Detector, Heat
15	Diaphragm
16	Disc, Rupture
17	Ells
18	Fasteners
19	Fittings
20	Flange
21	Float
22	Float (Gas-Oil)
23	Float (Oil-Water)
24	Foundation
25	Gasket
26	Gasket Ring
27	Gauges
28	Gland, Packing
29	Glass, Sight
30	Header
31	Heater
32	Hopper
33	Hopper, Bin Storage
34	Hose
35	Jet
36	Joint, Blast
37	Lamp, Indicator
38	Linkage
39	Liner
40	Meters
41	Nipple
42	Nipple, Landing
43	O-rings
44	Packers
45	Pig
46	Pipe
47	Piston
48	Plug, Bull
49	Pump
50	Recorders
51	Rectifier
52	Regulator, Pressure

FIELD 61-65
SYSTEM CODE
(Cont'd)

Code	Component
53	Relay, Electric
54	Relay, Pressure
55	Riser
56	Rods
57	Rod, Polished
58	Screen
59	Seals
60	Seam
61	Sensor, Level, High
62	Sensor, Level, Low
63	Sensor, Pressure, High
64	Sensor, Pressure, Low
65	Swage
66	Switches
67	Tank Shell
68	Tees
69	Threads
70	Tubing Hanger
71	Tubing, Instrument
72	Union
73	Union, Flange
74	Valve
75	Valve, Back Pressure
76	Valve, Ball
77	Valve, Blind
78	Valve, Body
79	Valve, By-Pass
80	Valve, Check, Reverse Flow
81	Valve, Control
82	Valve, Dump
83	Valve, Gate
84	Valve, Needle
85	Valve, Plug
86	Valve, Relief, Pressure
87	Valve, Trim
88	Vessel, Pressure
89	Welds
90	Wiring, Electrical
91	Motor
92	Fire-Tube
93	Controls
94	Vent
95	Test Tank
96	Oil Leg
97	Water Line/Leg
98	Fuel Supply Line/Leg
99	Strainer

FIELD 66
PIPE DIAMETER CODE

The pipe diameter information is desired when an oil spill is attributed to piping. Where the data permits, one of the following codes shall be entered to indicate the diameter of the pipe involved:

Code	Pipe Diameter
A	Unknown
B	Not Recorded
C	2" or less
D	2-1/2"
E	3"
F	4" or 4-1/2"
G	6"
H	8"
J	10"
K	12"
L	14" to 24"
M	26" to 40"
N	42" to 48"

INSTALLATION DATE CODE

The age of a petroleum system installation often has a large bearing on problems due to corrosion, wear, or other time-related factors. In anticipation that installation date information might be available regarding the various systems, a data code is available. The age factor is of sufficient importance to warrant its inclusion for each system oil spill event, where the data permits.

The following code is to be used to record the installation date:

Code	Time Period
1	Before 1920
2	1920-1929
3	1930-1939
4	1940-1949
5	1950-1959
6	1960-1969
7	1970-1971
8	Unknown
9	Not Reported

The Equipment Protection Code provides for information regarding protective coating of pipelines and cathodic protection as follows:

Code	Description
1	Coated - Cathodic Protection
2	Coated - No Cathodic Protection
3	Not Coated - Cathodic Protection
4	Not Coated - No Cathodic Protection
5	Coated - Cathodic Protection Not Reported
6	Not Coated - Cathodic Protection Not Reported
7	Cathodic Protection - Coating Not Reported
8	No Cathodic Protection - Coating Not Reported
9	No Protection Information Reported

The nature of the repair action instituted following a spill event serves to indicate whether or not there was a replacement, repair, or adjustment at a subsystem, equipment, or component level.

The repair action is listed as follows:

Code	Description
1	Replaced Subsystem
2	Replaced Equipment
3	Replaced Component
4	Repaired Equipment
5	Repaired Component
6	Adjusted
7	Not Reported
8	Repair Not Required
9	Removed From Service

The Spill Control Method Code permits recording the type and amount of control exercised in a particular case.

The following listing comprises the Spill Control Method Code:

Code	Description
0	Controlled, But Method Not Reported
1	Dammed
2	Dug Pit
3	Booms
4	Air Barrier
5	Soaked Into Ground Or Trapped in Natural Earth Depression
6	Dispersed Into Water
7	Contained Within Fire Walls
8	Retained Within System
9	Not Reported
A	Killed Well/Shut In

SPILL CLEANUP METHOD CODE

Frequently used actions for cleanup of oil spills are represented in the designed code. Regulations or laws often enforce some response. The speed of response or a mixture of various methods are not covered by this code. The cleanup method, when reported, together with the location and quantity spilled, improves the capability for data analysis.

The Spill Cleanup Method Codes are as follows:

Code	Description
0	Cleaned Up, But Method Not Reported
1	Vacuum
2	Burned
3	Skimmers
4	Soaked Up With Straw
5	Soaked Up With Urethane Foam Chips
6	Covered With Sand or Dirt
7	Turned Soil Under
8	Not Required
9	Not Reported

FIELD 77-78
COST CODE

An estimate of the cost of an oil spill is desired. By determining the cost related to spills, a basis of comparison can be established to balance against the cost of system improvements to prevent spills. To this end the cost code is used to identify major categories of cost, both by type of cost and dollar amount, falling in selected ranges.

The Cost Code consists of two positions. The first, Field 77, relates to the dollar range. The second, Field 78, relates to the nature of the costs. The 0 code in either position indicates "not reported."

Numeric

Code	(Field 77)
1	0 - 999
2	1,000 - 4999
3	5,000 - 9999
4	10,000 - 49999
5	50,000 or over
0	Not Reported

Alpha

Code	(Field 78)
A	Property Damage
B	Cleanup
C	Loss of Oil Spilled
D	Loss of Oil Production
E	Repair or Restoration
F	A & B
G	A & C
H	B & C
J	A & B & C
K	B & C & E
0	Not Reported

FIELD 80
VIOLATION CODE

Laws or regulations may be violated in connection with the occurrence of an oil spill event. This code is provided to indicate where such violations are reported. The data are desired to support analysis and recommendations regarding enforcement of or change in regulations which will tend to eliminate or reduce pollution of the environment as a result of oil spillage.

The Violation Code is as follows:

Code	Violation
1	Yes
2	No
3	None Reported